June 2, 2026

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Re: Case No. U-22070 – 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 Application, a Proposed Notice of Hearing, non-modifiable Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses**. Also included is a Proof of Service showing service upon the parties in Consumers Energy Company's last two electric rate cases (Case Nos. U-21585 and U-21870). This is a paperless filing and is therefore being filed only in PDF.

Confidential materials of Company witnesses Stacy H. Baker, Thomas P. Clark, Emily M. Duke, Kendra K. Grob, Michael C. Grondin, Joshua J. Judy, Sara E. Stewart, and Mark E. Wittbrodt are being filed under seal with the Michigan Public Service Commission.

In accordance with filing procedures adopted by the Michigan Public Service Commission in Case No. U-18238: (i) exhibits that were prepared in Microsoft Excel format are being filed in Excel with formulas intact in addition to PDF; (ii) tariff changes are being filed in Microsoft Word in addition to PDF with changes shown in redline format; and (iii) workpapers and economic models used to support the rate increase request will be provided to parties in Microsoft Excel with formulas intact. Also provided to the Michigan Public Service Commission is Consumers Energy Company's Part II – Financial Information materials in the above docket via a secure link.

Digital copies of the public rate case filing, including native and PDF testimony, exhibits, workpapers, and models of Consumers Energy Company's witnesses, and Consumers Energy Company's Part II – Financial Information and Part III – Supplemental Data materials are being provided to the MPSC Staff and parties to Case Nos. U-21585 and U-21870 concurrently with this filing via a secure link and this link will be made available to any parties to Case No. U-22070 who were not previously served.

Sincerely,



Gary A. Gensch Jr.
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cc: Mike Byrne, Executive Director, MPSC Staff
Nick Revere, MPSC Staff
Bill Stosik, MPSC Staff
Paul Proudfoot, MPSC Staff
Bob Nichols, MPSC Staff
Anne Armstrong, MPSC Staff
Parties to Case Nos.U-21585 and U-21870

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") authorize Consumers Energy to increase its rates for the sale of electricity and grant it additional relief as set forth herein. In support of this Application, Consumers Energy states as follows:

I. INTRODUCTION

1. Consumers Energy is, among other things, engaged as a public utility in the business of generating, purchasing, distributing, and selling electric energy to approximately 1.9 million retail customers in the state of Michigan. The retail electric system of Consumers Energy is operated as a single utility system, within which it charges uniform rates.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Commission pursuant to various provisions of 1909 PA 106, as amended, MCL 460.551 *et seq*., 1919 PA 419, as amended, MCL 460.54 *et seq*., and 1939 PA 3, as amended, MCL 460.1, *et seq*. Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate Consumers Energy's retail electric rates.

3. The Commission approved Consumers Energy's current retail electric base rates in its March 27, 2026 Order in Case No. U-21870 ("U-21870 Order"). In addition, the Commission

has authorized, through various orders, the recovery of certain additional costs as set forth in the Company's tariffs on file with the Commission, including Power Supply Cost Recovery factors, Renewable Energy Plan surcharges, Energy Waste Reduction surcharges, Demand Response surcharges, Distribution Deferral surcharges, Investment Recovery Mechanism surcharges, and securitization bond charges.

II. REQUESTED RATE RELIEF

4. For purposes of this case, Consumers Energy has undertaken a complete examination of relevant items of investment, expense, and revenues for the determination of just and reasonable retail electric rates, using a projected test year for the 12-month period ending April 30, 2028. Using a projected test year for the 12-month period ending April 30, 2028 will allow the rates established in this case to more closely reflect investments made and expenses incurred during the time rates established in this case are in effect.

5. Consumers Energy has calculated that, without rate relief, it will experience an annual jurisdictional electric revenue deficiency of approximately $456 million for the 12-month period ending April 30, 2028. The Company is also requesting recovery of an additional $25 million for the distribution deferral through a 12-month surcharge. An increase in Consumers Energy's electric rates is required to afford the Company a reasonable opportunity to recover its reasonable costs of providing electric service, including a reasonable return on common equity, as more fully described in the accompanying testimony and exhibits. Without rate relief, Consumers Energy's retail electric rates will be so low as to deprive Consumers Energy of a reasonable return on the Company's property, and amount to confiscation and deprivation of the Company's property, contrary to the Company's rights under the Constitutions of the United States and of the State of Michigan.

6. The Company has determined revenue requirements using a fully projected sales forecast for the projected test year.

7. In determining its revenue requirements for this filing, Consumers Energy has used the depreciation rates authorized by the Commission in Case No. U-20849 for its electric and common plant, excluding the Ludington Pumped Storage plant. For the Company's Ludington Pumped Storage plant, the calculated depreciation expense and associated accumulated depreciation presented used depreciation rates approved in Case No. U-20844.

8. Consumers Energy proposes that rates established in this case include an authorized rate of return on common equity of 10.25%, and reflect an overall rate of return on total rate base of 6.59%. The Company submits that the requested returns reasonably balance interests of customers and investors. The Company is requesting a 51.75% common equity ratio in this case.

9. The electric service Consumers Energy provides is necessary to customers' lives and livelihoods. Customers depend on it to be there – on demand – to power the appliances and devices we rely on for our entire way of life. But the reliability and resiliency of the electric distribution system is challenged by increasingly severe weather and deterioration of the system. In the face of these challenges, and in response to the calls of the Commission and other stakeholders for improved reliability, the Company is continuing on its comprehensive and prudent strategy for improving reliability through investments in and maintenance of core traditional infrastructure such as poles, wires, and substations, as well as enabling the transition to cleaner energy resources and increasing automation of the system. Like the Commission and other stakeholders, the Company's goal is fewer and shorter power outages for customers. A primary driver of the Company's requested rate relief is the investments needed for the delivery of safe,

reliable and resilient, clean and equitable, and competitive energy to Consumers Energy's customers. Without these investments, the desired improvements in reliability cannot occur.

10. The Company's planned activities and investments in the distribution system are expected to improve the System Average Interruption Duration Index, excluding Major Event Days, to the second quartile by 2029. This improvement in reliability follows through on the Company's commitment to delivering reliable electric service to customers and responds to the Commission's and stakeholders' expectations for significantly improved reliability.

11. The distribution system improvements supported by the funding requested in this case include (but are not limited to) the following activities vital to achieving the Company's important reliability and safety objectives:

- Continuing the Vulnerable Communities Resiliency Plan to make targeted investments to improve reliability on Environmental Justice circuits;
- Expanding undergrounding of distribution lines to deliver cost-effective reliability and resiliency benefits;
- Enhancing safety through voltage conversions, subsurface transformer replacements, open-wire secondary conversions, and replacement of poles in poor asset health;
- Mitigating the risk of wildfires through situational awareness, operational procedures, vegetation management, and system hardening;
- Fractionalization to segment circuits into smaller sections with fewer customers to reduce the number of customers impacted by outages;
- Performing inspections to identify, and then fix, failures on the system;
- Automatic Transfer Recloser Loops, which automatically restore power to impacted customers when power loss is detected;
- Making targeted circuit health improvements to mitigate problems with conductor, poles, and other supporting components;
- Grid Automation investments that improve reliability for customers; and

- Identifying and addressing locations on the system where customers experience more frequent outages.

12. Consumers Energy is continuing its ramp-up in line clearing to achieve a five-year clearing cycle on the low voltage distribution ("LVD") system. The ramp up to a five-year cycle is planned to occur through 2031, after which the Company will maintain the five-year cycle. To mitigate the customer impact of this ramp up, the Company is proposing to continue to defer the amounts above the baseline line clearing expense to a regulatory asset.

13. In the U-21870 Order, the Commission approved an Investment Recovery Mechanism ("IRM") for LVD Lines Reliability, System Protection, and Resiliency covering the 12-month period ending April 30, 2027. Customers benefit from the certainty of investments in the capital programs included in the IRM that are critical to improved reliability. As part of the IRM, the Company remains committed to transparent planning and a reconciliation process that discourages the Company from shifting dollars away from these critical system investments and provides refunds to customers in the event of underspending in these areas. The Company is proposing an IRM that will cover a two-year period beginning May 1, 2027, consistent with the start of the test year in this case. Consumers Energy proposes to continue the IRM using the same investment categories approved by the Commission in Case No. U-21870 with the addition of one new sub-program: high voltage distribution ("HVD") Lines Reliability. The Company proposes that the spending levels included in the IRM for the 12 months ending April 30, 2028 be set at test year levels approved for each program in this case and year 2 of the IRM should be equal to year 1 spending levels. The Company is also proposing a corresponding update to the IRM surcharge.

14. Additional factors contributing to Consumers Energy's need for electric revenues above levels currently recovered in base rates include:

(i.) Investments in electric utility generation assets to provide safe, reliable, and economic energy and capacity for customers;

(ii.) Investments in assets to comply with safety and legal requirements;

(iii.) Investments in the Company's fleet and facilities;

(iv.) Operating and maintenance ("O&M") expenses necessary to, among other things, support long-term investments; and

(v.) Increased financing costs to attract capital for the Company's necessary investments.

15. The Company has made filings with the Federal Energy Regulatory Commission ("FERC") and the MPSC (FERC Docket No. EC26-20-000 and MPSC Case No. U-21985) seeking approval for the FERC license transfer, sale of all 13 river hydro facilities ("River Hydros"), and associated power purchase agreement. In the U-21870 Order, the Commission authorized the Company to use deferred regulatory accounting of the revenue requirement on actual capitalized investments incurred due to the uncertainty of the disposition of the River Hydros. Because of the continued uncertainty, the Company requests continuation of this deferral through the test year of this rate case. O&M expense needed to safely operate the River Hydros has been included in the case. If actual O&M expense is lower than amounts included in rates, the Company proposes to defer the difference to a regulatory liability for refund to customers.

16. On May 23, 2025, the U.S. Secretary of Energy issued Order No. 202-25-3 ("DOE Order") requiring Consumers Energy to continue operating the Campbell Plant beyond May 31, 2025. Subsequently, the Secretary of Energy issued four additional emergency orders for 90 days each, the most recent of which requires continued operation of the Campbell Plant through August 16, 2026. The Company continues to coordinate with the Midcontinent Independent System Operator, Inc. ("MISO") and has complied with the DOE Order. The costs presented in this electric rate case include the continued recovery of the net book value of the Campbell plant as approved in Case No. U-21090. This electric rate case does not include any additional costs related to the impacts of any DOE Order. In January 2026, the Company filed a request at FERC seeking

recovery of the net financial impact of complying with the May 2025 emergency order. FERC approval of that cost recovery filing is pending. Any amounts recovered through the FERC cost recovery filing that have also been recovered through MPSC jurisdictional rates will be refunded to MPSC jurisdictional customers.

17. The SAP S4/HANA Project will modernize the Company's current Enterprise Resource Planning solution that will reach the end of mainstream vendor maintenance in 2027. Operating the system beyond the end of the support date would create significant risks, including the inability to comply with regulatory requirements, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber security protection. The Company is proposing the continuation of the accounting treatment approved in Case No. U-21870 to defer the associated O&M expense and amortize it over 15 years, as well as the 15-year amortization for the cloud implementation costs. The Company is proposing that the 15-year amortization begins after the Company completes all releases for the project.

18. Consumers Energy is including costs associated with its Demand Response ("DR") programs in this case. DR programs help manage capacity need for peak demand, assisting in balancing Michigan's electricity needs to help protect the grid, react to emergencies and severe weather, and avoid the cost of additional generation infrastructure to serve peaks. Consumers Energy is also requesting approval of the reconciliation of 2025 DR costs and the approval of a 2025 DR performance incentive.

19. Consumers Energy is also supporting funding for Transportation Electrification Plan programs, which are centered on optimizing the charging load from electric vehicles to the benefit of all customers, and investments, incentives, programs, and expenditures that are reasonably expected to increase transportation electrification in the Company's electric service

territory. These programs include PowerMIDrive Residential, PowerMIDrive Public, and PowerMIFleet. The Company is proposing certain enhancements to the programs in this case.

III. RATE DESIGN, TARIFF, AND OTHER PROPOSALS

20. Pursuant to the requirements of MCL 460.11(1), the Company proposes to establish rates based on the cost of providing service to each customer class. In order to comply with that requirement, among other things, the Company is sponsoring a Cost-of-Service Study that uses the methodologies previously approved by the MPSC in Case No. U-21870.

21. Consumers Energy proposes to allocate the required electric revenue increase among rate classes as set forth in Attachment A to this Application. A comparison of typical residential bills under present and proposed rates is shown on Attachment B to this Application.

22. In addition to requesting authority to increase the level of rates and charges, Consumers Energy is proposing various revisions to its electric rules, regulations, and tariffs. Consumers Energy's testimony and exhibits provide additional details on the requested relief. Among other revisions and clarifications, Consumers Energy is proposing to: (i) update the overhead line extension fees; (ii) clarify treatment of customers upon expiration of their Experimental Advanced Renewable Program contract; (iii) update new service connection fees; (iv) revise the Transportation Electrification Plan programs to streamline program administration, remove unused or unnecessary provisions, and update eligibility and metering requirements; (v) include an electric heating rate with a six-month implementation period; (vi) adjust the Large Economic Development Rate to add a power factor adjustment and update the production capacity charge based on the latest forecasted MISO Cost of New Entry; (vii) close the General Service Unmetered Lighting Rate and transition customers to the General Unmetered Light-Emitting Diode Lighting Rate; and (viii) remove the credit offered to the Peak Time Rewards control group.

23. In Case No. U-21585, the Commission approved the deferred accounting associated with actual capital spending from March 1, 2025 through February 28, 2026 above the amounts set in rates for the following distribution programs: New Business, Demand Failures, and Asset Relocation, and to continue such deferral until actual amounts are included in rates. In Case No. U-21870, the Commission approved continued use of this deferred accounting, with updated capital spending amounts. For the period of March 1, 2025 through February 28, 2026, the Company had actual capital spending above the amount included in rates for these three programs. The Company is proposing a 12-month surcharge to collect the $25 million of additional revenue requirement that would have been built into rates if the additional capital spending had been included. The Company also requests to continue the deferral mechanism approved in Case No. U-21870 for the capital spending in the test year of this case, the 12 months ending on April 30, 2028.

24. In March/April 2025, Consumers Energy experienced a series of severe, multi-waive weather events across its electric service territory that resulted in widespread system damages and customer outages. These events included significant ice accumulation, severe thunderstorms, damaging winds, and tornadoes. In Case No. U-21914, the Commission granted the Company accounting authority to use a regulatory asset to defer O&M expense associated with the March/April 2025 storm event, subject to Commission review of the reasonableness and prudence of the costs in a separate proceeding. As a result, the Company deferred $52 million of O&M expense, and has provided storm data, cost details, and other support showing that restoration efforts were conducted in a reasonable, cost-effective manner. The Company requests approval to recover the deferred amount over a three-year amortization period.

25. The Company's testimony and exhibits in support of this Application also request recovery of associated amortization expense for the D. E. Karn Units 1 and 2 and J.H. Campbell ("Campbell") Units 1, 2, and 3 retention, decommissioning, and ash disposal costs, and the Classic 7 ash disposal costs; deferred costs and amortization expense for the PowerMIDrive and PowerMIFleet programs; and amortization expense for the Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism. In addition, as previously approved by the Commission, the remaining net book value of Campbell Units 1, 2, and 3 has been placed in a regulatory asset and the associated regulatory asset balance and amortization expense are included in this case.

26. The Company also requests the use of regulatory assets or regulatory liabilities, as needed, related to: (i) the continued deferral of certain distribution capital spending in New Business, Demand Failures, and Asset Relocation until actual amounts are included in rates; (ii) line clearing program ramp-up deferral; (iii) continued deferral of River Hydro costs; (iv) the deferral related to the Staking and Locating Program; (v) the SAP S4/HANA Project deferral and amortization; (vi) continued deferral of expenditures associated with the PowerMIDrive and PowerMIFleet programs; (vii) continued deferral associated with the Pension/Other Post-Employment Benefits Volatility Mechanism; and (viii) deferral for future recovery of Michigan income tax expense if the Company is unsuccessful in defending its apportionment methodology. The Company also requests approval to recover Illinois state income tax expense in future rate cases.

IV. TESTIMONY, EXHIBITS, AND RESERVATION OF RIGHT TO AMEND

27. Consumers Energy is, concurrently with this Application, filing written testimony and exhibits in support of rate relief and other relief that the Company is seeking in this case. Reference to this material will provide additional details on the relief being sought. The relief

described in the testimony and exhibits should be considered as if specifically requested in this Application. Consumers Energy reserves the right to revise, amend, or otherwise change the relief it is requesting in any way appropriate depending upon the duration and progress of hearings in this proceeding, the issuance of orders that have an impact upon this case, or the occurrence of other material events.

28. In addition to the issues described above, other pending or to-be-filed proceedings or other events may impact the rate adjustments requested at this time. These impacts will be evaluated for materiality and may need to be considered in the results of this proceeding.

V. REQUEST FOR RELIEF

WHEREFORE, Consumers Energy Company requests that the Michigan Public Service Commission:

A. Authorize Consumers Energy to adjust its retail electric rates so as to provide additional revenue of approximately $456 million annually above levels established in Case No. U-21870 based on a projected 12-month test year ending April 30, 2028, plus an additional $25 million for the distribution deferral;

B. Authorize Consumers Energy to adjust its existing retail electric rates so as to produce a rate of return on common equity of not less than 10.25%;

C. Approve the proposed Distribution Deferral and Investment Recovery Mechanism surcharges;

D. Approve modifications to the rates, rules, regulations, and programs as are described in the testimony and exhibits that accompany this Application;

E. Approve the Company's accounting requests and use of regulatory assets or regulatory liabilities, as needed, as described in the accompanying testimony; and

F. Grant Consumers Energy such other and further relief as is just and reasonable.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: June 2, 2026 By: _____

Kelly M. Hall
Senior Vice President, Regulatory and
Legal Affairs and Deputy General Counsel
Consumers Energy Company

_____

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

VERIFICATION

Kelly M. Hall, states that she is Senior Vice President, Regulatory and Legal Affairs and Deputy General Counsel of Consumers Energy Company; that she has executed the foregoing Application for and on behalf of Consumers Energy Company; that she has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of her knowledge and belief; and that she is duly authorized to execute such Application on behalf of Consumers Energy Company.

Dated: June 2, 2026 By: Kelly M. Hall

Kelly M. Hall
Senior Vice President, Regulatory and
Legal Affairs and Deputy General Counsel
Consumers Energy Company

ATTACHMENT A

MICHIGAN PUBLIC SERVICE COMMISSION **ATTACHMENT A**

Consumers Energy Company

Summary of Present and Proposed Pro Forma Revenues by Rate Schedule

U-22070

Line No.	Description	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
		(a)	(b)	(c)	(d)	(e)
		$000	$000	$000	%
	FULL SERVICE				
	Residential Class				
1	Summer On-peak RSP	$ 2,571,968	$ 2,824,661	$ 252,693	9.8
2	Smart Hours RSH	43,348	47,569	4,221	9.7
3	Night Time Savers RPM	37,330	41,075	3,745	10.0
4	Non-Transmitting Meters RSM	23,194	25,414	2,220	9.6
5	Electric Heating REH	-	-	-	NA
6	Total Residential Class	$ 2,675,840	$ 2,938,720	$ 262,880	9.8
	Secondary Class				
7	Energy-only GS	$ 765,021	$ 833,541	$ 68,520	9.0
8	Time-of-Use GSTU	18,884	20,591	1,707	9.0
9	Demand GSD	465,204	502,734	37,530	8.1
10	Total Secondary	$ 1,249,109	$ 1,356,866	$ 107,757	8.6
	Primary Class				
11	Energy-only GP	$ 79,683	$ 82,853	$ 3,169	4.0
12	Demand GPD	447,741	475,040	27,299	6.1
13	Time-of-Use GPTU	479,510	514,626	35,116	7.3
14	Energy Intensive EIP	32,196	34,619	2,423	7.5
15	Total Primary	$ 1,039,131	$ 1,107,138	$ 68,008	6.5
	Lighting & Unmetered Class				
16	Metered Lighting GML	$ 1,887	$ 2,171	$ 284	15.0
17	Universal Unmetered Lighting UUL	33,568	37,438	3,871	11.5
18	Unmetered GU	10,958	12,069	1,111	10.1
19	Total Lighting & Unmetered	$ 46,413	$ 51,679	$ 5,265	11.3
	Self-generation Class				
20	Small Self-generation GSG-1	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	14,904	15,469	565	3.8
22	Total Self-generation	$ 14,904	$ 15,469	$ 565	3.8
23	Total Full Service	$ 5,025,396	$ 5,469,872	$ 444,476	8.8
	ROA SERVICE				
	Secondary Class				
24	Energy-only GS	$ 1,197	$ 1,465	$ 268	22.4
25	Demand GSD	10,052	11,910	1,858	18.5
26	Total Secondary	$ 11,249	$ 13,375	$ 2,126	18.9
	Primary Class				
27	Energy-only GP	$ 1,750	$ 2,189	$ 439	25.1
28	Demand GPD	32,429	40,572	8,143	25.1
29	Total Primary	$ 34,179	$ 42,761	$ 8,582	25.1
30	Total ROA Service	$ 45,428	$ 56,136	$ 10,708	23.6
31	Total Jurisdictional Service	$ 5,070,824	$ 5,526,008	$ 455,184	9.0
32	Plus: Rounding	-	19	650	
33	Total Jurisdictional Revenues	$ 5,070,824	$ 5,526,027	$ 455,203	9.0
34	Less: PSCR Factor Revenues	421,051	421,051	-	
35	Less: DR Surcharge	50,877	-	(50,877)	
36	Less: IRM Surcharge		20,235	20,235	
37	Total Jurisdictional Base Revenues	$ 4,598,896	$ 5,084,741	$ 485,845	10.6
38	Total Jurisdictional Revenues	5,070,824	5,526,027	455,203	9.0
39	Plus: ERC Deferral Surcharge		25,017	25,017	
40	Total Jurisdictional Revenues Requested	$ 5,070,824	$ 5,551,044	$ 480,220	9.5

ATTACHMENT B

MICHIGAN PUBLIC SERVICE COMMISSION **ATTACHMENT B**

Consumers Energy Company

Comparison of Present and Proposed Monthly Bills

Residential Summer On-peak RSP

U-22070

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	9.05	9.16	0.11	1.2%	183.2	8.90	9.00	0.10	1.1%	180.0
2	50	18.51	19.59	1.08	5.8%	39.2	17.01	18.01	1.00	5.9%	36.0
3	100	29.03	31.18	2.16	7.4%	31.2	26.03	28.03	2.00	7.7%	28.0
4	150	39.54	42.77	3.23	8.2%	28.5	35.04	38.04	3.00	8.6%	25.4
5	200	50.05	54.36	4.31	8.6%	27.2	44.05	48.05	4.00	9.1%	24.0
6	250	60.56	65.95	5.39	8.9%	26.4	53.06	58.06	5.00	9.4%	23.2
7	300	71.08	77.54	6.47	9.1%	25.8	62.08	68.08	6.00	9.7%	22.7
8	350	81.59	89.13	7.54	9.2%	25.5	71.09	78.09	7.00	9.8%	22.3
9	400	92.10	100.72	8.62	9.4%	25.2	80.10	88.10	8.00	10.0%	22.0
10	450	102.61	112.31	9.70	9.5%	25.0	89.11	98.12	9.00	10.1%	21.8
11	500	113.13	123.90	10.78	9.5%	24.8	98.13	108.13	10.00	10.2%	21.6
12	550	123.64	135.49	11.86	9.6%	24.6	107.14	118.14	11.00	10.3%	21.5
13	600	134.15	147.08	12.93	9.6%	24.5	116.15	128.15	12.00	10.3%	21.4
14	650	144.66	158.67	14.01	9.7%	24.4	125.17	138.17	13.00	10.4%	21.3
15	700	155.18	170.27	15.09	9.7%	24.3	134.18	148.18	14.00	10.4%	21.2
16	750	165.69	181.86	16.17	9.8%	24.2	143.19	158.19	15.00	10.5%	21.1
17	800	176.20	193.45	17.24	9.8%	24.2	152.20	168.21	16.00	10.5%	21.0
18	850	186.71	205.04	18.32	9.8%	24.1	161.22	178.22	17.00	10.5%	21.0
19	900	197.23	216.63	19.40	9.8%	24.1	170.23	188.23	18.00	10.6%	20.9
20	950	207.74	228.22	20.48	9.9%	24.0	179.24	198.24	19.00	10.6%	20.9
21	1,000	218.25	239.81	21.56	9.9%	24.0	188.26	208.26	20.00	10.6%	20.8
22	1,500	323.38	355.71	32.33	10.0%	23.7	278.38	308.39	30.00	10.8%	20.6
23	2,000	428.50	471.62	43.11	10.1%	23.6	368.51	408.51	40.00	10.9%	20.4
24	2,500	533.63	587.52	53.89	10.1%	23.5	458.64	508.64	50.00	10.9%	20.3
25	3,000	638.76	703.42	64.67	10.1%	23.4	548.77	608.77	60.01	10.9%	20.3
26	3,500	743.88	819.33	75.45	10.1%	23.4	638.89	708.90	70.01	11.0%	20.3
27	4,000	849.01	935.23	86.22	10.2%	23.4	729.02	809.03	80.01	11.0%	20.2
28	4,500	954.13	1,051.13	97.00	10.2%	23.4	819.15	909.16	90.01	11.0%	20.2
29	5,000	1,059.26	1,167.04	107.78	10.2%	23.3	909.28	1,009.29	100.01	11.0%	20.2

Proposed Notice of Hearing
MPSC Case No. U-22070

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
NOTICE OF HEARING
FOR THE ELECTRIC CUSTOMERS OF
CONSUMERS ENERGY COMPANY
CASE NO. U-22070

- Consumers Energy Company requests the Michigan Public Service Commission for authority to increase its rates for the generation and distribution of electricity and for other relief.

- The information below describes how a person may participate in this case.

- You may call or write Consumers Energy Company, One Energy Plaza, Jackson, Michigan 49201, (800) 477-5050 for a free copy of its application. Any person may review the application at the offices of Consumers Energy Company or on the Commission's website at: michigan.gov/mpscedockets.

- A pre-hearing will be held:

DATE/TIME: **_____, 2026, at 9:00 a.m.**

BEFORE: **Administrative Law Judge _____**

LOCATION: **Video/Teleconferencing**

PARTICIPATION: Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8096, or by email at mpscedockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a public hearing to consider Consumers Energy Company's (Consumers Energy) June 2, 2026 application requesting the Commission to: 1) authorize Consumers Energy to adjust its retail electric rates so as to provide additional revenue of approximately $456 million annually above levels established in Case No. U-21870 based on a projected 12-month test year ending April 30, 2028, plus an additional $25 million for the distribution deferral; 2) authorize Consumers Energy to adjust its existing retail electric rates so as to produce a rate of return on common equity of not less than 10.25%; 3) approve the Distribution Deferral and Investment Recovery Mechanism surcharges as proposed by Consumers Energy; 4) approve modifications to the rates, rules, regulations, and programs as described and proposed by Consumers Energy; 5) approve Consumers Energy's proposed accounting requests and use of regulatory assets or regulatory liabilities, as needed, as described in Consumers Energy's filing; and 6) grant Consumers Energy other and further relief as is just and reasonable.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets Website at: https://mi-psc.my.site.com/s/. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in PDF format, as an attachment to an email sent to mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by e-mail at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____, 2026. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon Consumers Energy Company Legal Department - MPSC Regulatory, One Energy Plaza, Jackson, Michigan 49201.

The prehearing is scheduled to be held remotely by video conference or teleconference. Persons filing a petition to intervene will be advised of the process to participate in the hearing.

Any person wishing to appear at the hearing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of their wish to make a statement of position. Mich Admin Code, R 792.10413 (Rule 413).

Any person wishing to file a public comment may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. U-22070. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917.

All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's Web site, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Executive Secretary at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and Parts 1 & 4 of the Michigan Office of Administrative Hearings and Rules, Mich. Admin Code, R 792.10106 and R 792.10401 through R 792.10448.

[CONSUMERS ENERGY COMPANY HAS REQUESTED THE INCREASES AND OTHER PROPOSALS DESCRIBED IN THIS NOTICE. THE MICHIGAN PUBLIC SERVICE COMMISSION MAY GRANT OR DENY THE REQUESTED INCREASES AND OTHER PROPOSALS, IN WHOLE OR IN PART, AND MAY GRANT LESSER OR GREATER INCREASES THAN THOSE REQUESTED AND MAY AUTHORIZE A LESSER OR GREATER RATE FOR ANY CLASS OF SERVICE THAN THAT REQUESTED.]

_____, 2026

NON-MODIFIABLE PROTECTIVE ORDER

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that any Party discloses to another Party during the course of this proceeding. This Protective Order protects non-public, confidential information and materials so designated by the Disclosing Party as Protected Material, as defined herein. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's application, exhibits, discovery or audit responses, any witness' related exhibits and testimony, motions, objections, briefing, responses to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission), and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall also consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-

transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order.

2. Information that is protected as confidential in another jurisdiction that the Applicant provides utility service, and the source of the other jurisdiction's protective designation is made known to the Receiving Party.

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Applicant" refers to the filing party in this proceeding.

D. "Disclosing Party" means a Party producing Protected Material in this proceeding.

E. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this case under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

F. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material. A Receiving Party is responsible for assuring that persons,

representatives, or agents under its control or supervision comply with this Protective Order.

G. "Reviewing Representative" means a representative of the Receiving Party who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.G.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or an employee or other representative of a Receiving Party with significant responsibility in this case.

H. "Nondisclosure Certificate" refers to Attachment 1 to this Protective Order.

Except as otherwise provided herein, the Reviewing Party and Reviewing Representatives will be required to sign Nondisclosure Certificates. However, Nondisclosure Certificates will not be required from administrative law judges, members of the Commission and its support staff, Staff (excluding consultants, third-party experts, agents or other similar persons), and Staff counsel, for whom by virtue of their employment are presumed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all provided Protected Material. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party and a Reviewing Representative shall be maintained in a secure place. Access to Protected Material shall be limited to the Receiving

Party and the Reviewing Representative, after each has executed the Nondisclosure Agreement and provided a copy of the Nondisclosure Agreement to the Disclosing Party, subject to the limited exception in Paragraph I.H.

B. Protected Material must be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party and Reviewing Representative may analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. A Reviewing Representative shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party may request the Receiving Party withhold certain information from a Reviewing Representative and retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, then the Disclosing Party shall submit the dispute to the presiding hearing officer simultaneously upon objection. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. If a Receiving Party seeks access to Critical Energy Infrastructure Information ("CEII") as defined in 16 U.S.C § 824o-1(a)(3) and FERC rules, specifically 18 CFR § 388.113(c), the Receiving Party and Reviewing Representative shall also sign the CEII Nondisclosure Certificate (Attachment 2 to this Protective Order) and provide a copy of the

executed CEII Nondisclosure Certificates to the Disclosing Party.

E. The obligations under this Protective Order do not expire by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal.

F. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

G. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall identify what portion(s) of any document designated confidential it considers confidential. This can be done through highlights or other clear identifier. The Disclosing Party must mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22070." Software executable files containing Protected Material may not be capable of being marked with the foregoing required protective language. The inability to mark software executable files containing Protected Material with such protective language shall not diminish the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing Protected Material is marked with the required protective

language. However, any output from the software executable files containing Protected Material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required protective language, shall be marked by the party who generated the output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22070." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer

to Protected Material, shall be marked or identified as, "CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-22070" and shall be maintained in a separate portion of the record under seal, segregated in the files of the Commission, and withheld from inspection by any person not bound by the terms of this Order.

C. The Protected Material subject to this Order shall be shielded from disclosure to the extent permitted by law. If any person files a request under the Freedom of Information Act ("FOIA") with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary, Staff, or the Attorney General shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the MPSC, Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge by motion whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. The Receiving Party challenging the protected status of the document must explicitly state its reason for challenging the confidential designation. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling and a request for a stay to the Commission pursuant to R 792.10433. If the application for leave is timely, the document's protected status will continue during the Commission appeal process. Any Party opposing the application for leave to appeal

and the stay shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. Continued protected status post order, will be determined by the Commission in its order addressing the application for leave and the request for stay. Nothing in this paragraph shall prohibit the Disclosing Party from seeking a stay on appeal of the Commission's decision regarding the revocation of any document's protected status.

B. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party and, except as required by applicable law and State retention schedules, only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. If the Disclosing Party seeks to have the Receiving Party return all Protected Material in the Receiving Party's possession or in the possession of its Reviewing Representatives, or certify in writing that all Protected Material has been destroyed, it is the responsibility of the Disclosing Party to contact the Receiving Party and make its request no earlier than the expiration of time for filing petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. Further, for a Receiving Party that is associated with the State, the request must be consistent with the expiration of the State retention requirement.

Notwithstanding the foregoing, counsel for the Receiving Party may maintain a single confidential file of Protected Material subject to all other provisions in this Order. Should

counsel seek to refer to the Protected Material in another Commission proceeding, the Disclosing Party must be the Applicant in said proceeding and counsel must ensure there is a protective order in said proceeding which protects the Protected Material from public disclosure.

VI. Limitations and Disclosures

This Protective Order does not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.4. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying all Parties and the presiding hearing officer in writing. The written notice must identify the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

VIII. Modification

Formal Addendums to this agreement may be established by an ALJ upon motion by any party and after notice and hearing.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

_____
Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Attachment 1

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-22070, that I have read the Protective Order, and that I agree to be bound by the terms of the Protective Order.

Reviewing Representative:

Date:_____ _____

Receiving Party:

_____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Attachment 2

NONDISCLOSURE CERTIFICATE

FOR CRITICAL ELECTRIC INFRASTRUCTURE INFORMATION

I hereby agree and certify my understanding that access to Critical Electric Infrastructure Information ("CEII") as defined at 16 USC Section 824o-1(a)(3) and 18 CFR Section 388.113(c) is provided to me pursuant to the terms and restriction of this CEII Nondisclosure Certificate and the Protective Order issued in Case No. U-22070, that I have been given a copy of and have read the Protective Order, and I agree to be bound by the terms of this CEII Nondisclosure Certificate and the Protective Order. I further agree that:

1. I will use CEII only for the purpose for which it was requested;

2. I will only discuss CEII with a Party and/or Reviewing Representative;

3. I will keep CEII in a secure place in a manner that prevents unauthorized access;

4. I will destroy CEII or return it to the disclosing party upon request;

5. I understand that CEII is not subject to release under the Freedom of Information Act;

6. I understand that I am obligated to protect CEII even after a designation as CEII has lapsed until a determination by the administrative law judge that the information should no longer be designated as CEII; and

7. I will report all unauthorized disclosures of CEII to the Disclosing Party.

Reviewing Representative:

Date:_____ _____

Title:_____

Receiving Party:_____

Printed Name:_____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on June 2, 2026, she served an electronic copy of **Consumers Energy Company's Application, a Proposed Notice of Hearing, non-modifiable Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

She further states that she provided the public versions of (i) Consumers Energy Company's Application, a Proposed Notice of Hearing, non-modifiable Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses in PDF format; (ii) exhibits in Excel format that were filed in Excel format; (iii) tariff changes in Word format that were filed in Word format; (iv) Workpapers in PDF and Excel format of Consumers Energy's witnesses; and (v) Consumers Energy Company's Part II and Part III Standard Filing requirements via secure filing sharing link at the email addresses listed in Attachment 1.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 2nd day of June, 2026.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-22070
(Parties to Case Nos. U-21585 and U-21870)

Party	Email Address
Counsel for Consumers Energy Company	
Gary A. Gensch, Jr., Esq. Bret A. Totoraitis, Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq. Michael C. Rampe, Esq.	gary.genschjr@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com spencer.sattler@cmsenergy.com evan.keimach@cmsenergy.com michael.rampe@cmsenergy.com mpsc.filings@cmsenergy.com
Counsel for the Michigan Public Service Commission Staff	
Amit B. Singh, Esq. Michael J. Orris, Esq. Adam M. Cozort, Esq. Nicholas Q. Taylor, Esq. Alena M. Clark, Esq. Daniel E. Sonneveldt, Esq. Anna B. Stirling, Esq.	singha9@michigan.gov orrism@michigan.gov cozorta1@michigan.gov taylorn10@michigan.gov clarkA55@michigan.gov sonneveldtd@michigan.gov stirlinga1@michigan.gov
Michigan Public Service Commission Staff	
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Counsel for Attorney General Dana Nessel	
Lucas Wollenzien, Esq. Celeste R. Gill, Esq. Amanda Churchill	wollenzienl@michigan.gov gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
Counsel for the Michigan Cable Telecommunications Association ("MCTA")	
Sean P. Gallagher, Esq. Jon Austin	sgallagher@fraserlawfirm.com jaustin@fraserlawfirm.com
Counsel for the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively "MNSC")	
Holly L. Hillyer, Esq. Christopher M. Bzdok, Esq. Tracy Jane Andrews, Esq. Natasha Fowles	holly@tropospherelegal.com chris@tropospherelegal.com tjandrews@tropospherelegal.com natasha@tropospherelegal.com
Counsel for the Citizens Utility Board of Michigan ("CUB")	
John Liskey, Esq.	john@liskeypllc.com
Counsel for The Kroger Co. ("Kroger")	
Kurt J. Boehm, Esq. Jody Kyler Cohn, Esq. Michael L. Kurtz, Esq.	kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com mkurtz@bkllawfirm.com
Counsel for Michigan Energy Innovation Business Council ("Michigan EIBC"), Institute for Energy Innovation ("IEI"), Advanced Energy United ("United"), Energy Michigan, Inc., and The Foundry Association of Michigan.	
Timothy J. Lundgren, Esq. Laura A. Chappelle, Esq. Justin K. Ooms, Esq.	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com jkooms@varnumlaw.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-22070
(Parties to Case Nos. U-21585 and U-21870)

Counsel for The Ecology Center, The Environmental Law & Policy Center ("ELPC"), Union of Concerned Scientists ("USC"), and Vote Solar (Collectively referred to as "CEO")	
Daniel Abrams, Esq. Katie Duckworth, Esq. Alondra Estrada Katie Toolan	dabrams@elpc.org kduckworth@elpc.org aestrada@elpc.org ktoolan@elpc.org mpscdockets@elpc.org
Counsel for Michigan Electric Transmission Company, LLC ("METC")	
Richard J. Aaron, Esq. Olivia R.C.A. Flower, Esq. Hannah Buzolits, Esq. Courtney F. Kissel, Esq.	raaron@dykema.com oflower@dykema.com HBuzolits@dykema.com ckissel@dykema.com mpscfilings@dykema.com
Counsel for Urban Core Collective ("UCC")	
Mark Templeton, Esq. Jacob R. Schuhardt, Esq. Emma Young	templeton@uchicago.edu jschuhardt@uchicago.edu eyoung28@uchicago.edu aelc_mpsc@lawclinic.uchicago.ed
Counsel for the Association of Businesses Advocating Tariff Equity ("ABATE")	
Stephen A. Campbell, Esq. Michael J. Pattwell, Esq. Benjamin J. Holwerda, Esq. Lauren Degnan	scampbell@clarkhill.com mpattwell@clarkhill.com bholwerda@clarkhill.com ldegnan@clarkhill.com
Counsel for Hemlock Semiconductor Operations LLC ("HSC") and Solar Technology LLC	
Jennifer Utter Heston, Esq.	jheston@potomaclaw.com
Counsel for Great Lakes Renewable Energy Association ("GLREA")	
Don L. Keskey, Esq.	donkeskey@publiclawresourcecenter.com
Counsel for Michigan Municipal Association for Utility Issues ("MAUI")	
Valerie J.M. Brader, Esq.	valerie@rivenoaklaw.com
Counsel for American Federation of Labor and Congress of Industrial Organizations ("AFL-CIO"), Michigan State Utility Workers Council ("MSUWC"), Utility Workers Union of American ("UWAU"), Local 223	
Benjamin L. King, Esq.	bking@michworkerlaw.com

* Receives Confidential Materials

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Revenue Requirements and Regulatory Affairs.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Accounting in 2003 from Michigan State University. I received a Master of Business Administration degree in 2012 from the University of Michigan – Flint. I am also a Certified Public Accountant licensed in the state of Michigan.

Q. Please describe your professional experience.

A. From 2004 to 2008 and from 2012 to 2015, I was employed by the Michigan Public Service Commission ("MPSC" or the "Commission") as an auditor and later as the Manager of the Revenue Requirements section. From 2008 to 2012 and 2015 to 2017, I was employed by the Lansing Board of Water and Light ("BWL"). During my tenure at the BWL, I held the following positions: Senior Rate Analyst, Executive Financial Assistant, Field Services Supervisor, Manager of Human Resources, and Supervisor of Finance and Planning. I joined Consumers Energy in January of 2017 as a Principal Rate Analyst and was promoted to Director of Revenue Requirements and Analysis in March of 2018 and was promoted to Executive Director of Revenue Requirements and Regulatory Affairs in June of 2020.

Q. What are your responsibilities as the Executive Director of Revenue Requirements and Regulatory Affairs at Consumers Energy?

A. As the Executive Director of Revenue Requirements and Regulatory Affairs, I am responsible for regulatory stakeholder collaboration and project management for the development of regulatory filings and communications as well as managing and preparing studies related to the level of the Company's revenue requirements, including the preparation and monitoring of gas and electric rate case filings before the Commission and other financial analysis. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery ("PSCR") monthly billing factors. In addition, beginning in July of 2023, I assumed responsibility for cost, pricing, and regulatory policy.

Q. Have you previously filed testimony with the Commission?

A. Yes.

Q. Please state the proceedings you have been involved in.

A. I sponsored testimony in the following cases:

Case No. U-14347 – Consumers Energy electric rate case;

Case No. U-14547 – Consumers Energy gas rate case;

Case No. U-17087 – Consumers Energy electric rate case;

Case No. U-17473 – Consumers Energy securitization;

Case No. U-18322 – Consumers Energy electric rate case;

Case No. U-20102 – Consumers Energy electric credit A;

Case No. U-20103 – Consumers Energy gas credit A;

Case No. U-20134 – Consumers Energy electric rate case;

Case No. U-20165 – Consumers Energy Integrated Resource Plan ("IRP");

Case No. U-20286 – Consumers Energy electric credit B;

Case No. U-20287 – Consumers Energy gas credit B;

Case No. U-20309 – Consumers Energy calculation C;

Case No. U-20697 – Consumers Energy electric rate case;

Case No. U-20889 – Consumers Energy securitization;

Case No. U-21389 – Consumers Energy electric rate case;

Case No. U-21490 – Consumers Energy gas rate case;

Case No. U-21585 – Consumers Energy electric rate case;

Case No. U-21806 – Consumers Energy gas rate case;

Case No. U-21911 – Consumers Energy incentive/disincentive;

Case No. U-21918 – Consumers Energy distribution Investment Recovery Mechanism ("IRM") reconciliation;

Case No. U-21870 – Consumers Energy electric rate case; and

Case No. U-21981 – Consumers Energy gas rate case.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's electric general rate case. My testimony introduces many of the key proposals included in this case and discusses how these proposals support the Company's long-range plans to provide safe, reliable, equitable, affordable, and clean energy for its customers. In addition, I give a brief introduction to the Company's witnesses and the topics supported in their respective testimony and I discuss the requirements for the Company's next electric rate case (*i.e.*, this case) as set forth in the Commission's March 27, 2026 Order in Case No. U-21870 ("U-21870 Order"). Finally, I support the Company's proposed Distribution IRM and ratemaking issues related to the Company's river hydro assets.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-166 (HJM-1)	Distribution Investment Recovery Mechanism – Annual Revenue Requirement

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

COMPANY OVERVIEW

Q. Please provide a brief description of Consumers Energy and its service territory.

A. Consumers Energy is a combination electric and natural gas utility proudly serving Michigan residents and businesses for 140 years. The Company, through its dedicated employees, provides safe, reliable, affordable, and increasingly clean electricity to 1.9 million customers in the Lower Peninsula. Consumers Energy's electric system is comprised of over 115,904 miles of distribution lines, 1,280 substations, and a diverse portfolio of generating plants located throughout the state. Consumers Energy is dedicated to achieving world-class performance delivering hometown service.

Q. Please briefly describe Consumers Energy's most recent Commission-approved electric general rate relief.

A. On March 27, 2026, the Commission issued an order in Case No. U-21870 approving a $217 million annual increase in the Company's electric rates and collection of a $24 million surcharge over 12 months for deferred costs related to distribution investments made during the 12 months ended February 28, 2025.

CASE OVERVIEW

Q. Please summarize the key drivers of the Company's request in this case.

A. The Company requests jurisdictional rate relief in the amount of $456 million and collection of $25 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2026 ("Distribution Deferral"). The Company's requested rate relief in this case is summarized in Table 1:

Table 1

	(In Millions)
Investment	$248
Operations and Maintenance Expenses	$46
Cost of Capital	$103
Sales/Revenues	$59
Jurisdictional Rate Relief Before Surcharge	**$456**
Distribution Deferral Surcharge	$25
Total Jurisdictional Rate Relief	**$481**

Q. Why has the Company initiated this rate case proceeding?

A. Consumers Energy's commitment to world-class performance delivering hometown service means providing safe, reliable, affordable, and increasingly clean energy to our 1.9 million customers each hour of every day. To deliver on this commitment, the Company has developed compelling testimony in this case, driven by the Company's Reliability Roadmap (historically known as the Electric Distribution Infrastructure Investment Plan or "EDIIP"), to make specific investments that address asset deterioration and maintain asset health, while also hardening assets against increasingly severe weather. The Company has also devoted considerable effort to developing long-range plans

addressing how to transform energy supply to cleaner resources through the Clean Energy Plan put forth in the Company's last ordered IRP, Case No. U-21090. Components of the IRP are incorporated into the Company's distribution strategy and vision within the Reliability Roadmap. Together these plans articulate the Company's goals for the future and provide a roadmap for the investments needed to bring this future to fruition.

Q. How has the Company's Reliability Roadmap influenced this filing?

A. As further explained by Company witness Emily M. Duke, the Company has filed the 2025 Reliability Roadmap in this case. This Reliability Roadmap was also included in Case No. U-21870. The Company has not made any subsequent revisions since the filing of Case No. U-21870. The 2025 Reliability Roadmap defines the Company's current distribution objectives and goals, and the investment plans to meet those objectives and goals, which are reflected in the proposed spending levels in this case. This Reliability Roadmap maintains planning that includes tools and methods of analysis to better anticipate future challenges. These tools and methods were first introduced in the third iteration of the EDIIP used as the starting point for the 2025 Reliability Roadmap filed in this case. This approach underpins the distribution investment request in this case supporting continued investments in infrastructure and spending on line clearing and inspections, while also focusing on resiliency investments. Proposed distribution spending is designed to meet the collective goal to deliver on the key objectives of the Reliability Roadmap – delivery of safe, reliable and resilient, clean and equitable, and competitive energy to Consumers Energy's customers.

The Company plans to file its next five-year distribution plan – which, per the Commission's guidance, will be titled the Distribution System Plan – by November 30, 2026, as required by the Commission in the July 10, 2025 Order in Case No. U-20147.

Q. How do the Company's proposals in this case support the Company's Reliability Roadmap and its commitment to improving reliability and resiliency?

A. Consumers Energy has plans necessary for transforming the electric distribution system by investing in core infrastructure assets and modernizing the electric grid to deliver safe, reliable and resilient, clean and equitable, and competitive electricity to customers. Proposals in this electric rate case support the four key objectives used in building the Reliability Roadmap. Company witnesses Duke, Jennifer M. Partlan, Kurt K. LaFrance, Scott A. McPhail, Daniel A. Schmoekel, Sara E. Stewart, and Jeffrey P. Dickey provide support for the Distribution investments and Distribution operating and maintenance ("O&M") programs. The Company's proposed electric distribution spending includes capital investments planned for the test year, the 12 months ending April 2028, that total more than $1.4 billion, as well as $489 million for O&M programs. These amounts are comprised of several important programs detailed in this case. The Company has proposed significant O&M funding, more than $168 million, to support the continued increase in the Company's line clearing activities to reduce the frequency of outages and move to a five-year line clearing cycle, as supported by Company witness Stewart. Where outages cannot be completely avoided through capital investment, line clearing, or other O&M, the Company continues to implement measures to decrease the frequency and shorten the duration of outages. Company witness Dickey supports the Company's service restoration

base O&M funding of $192.6 million based on the historical year cost, excluding deferred costs for the March/April 2025 storm, adjusted for inflation.

Q. What reliability improvements does the Company expect to see from the investments outlined in the Reliability Roadmap as proposed?

A. Reliability improvements provide significant benefits to customers, local communities, and the Michigan economy. The Company's proposed investments in distribution system infrastructure are based on the goal of providing safe and reliable electricity for customers while improving the Company's performance relevant to three reliability metrics — System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI"). Company witness Duke presents the Company's modeling projections demonstrating how planned investments are expected to improve reliability across these metrics as identified in the Reliability Roadmap. Based on the modeling results, the Company projects that customers will experience fewer outages on average, and when outages do occur, they will be for shorter periods of time. Projected reliability improvements are based on the Company's planned spending on line clearing, capital investments, and service restoration improvements outlined in the Reliability Roadmap. As explained by Company witness Duke, these reliability improvements cannot be achieved based on increased line clearing alone. The reliability improvements presented in this case are dependent on necessary and continued investments in the distribution system. Benefits of shifting to a five-year clearing cycle will take time to fully materialize and a line clearing only approach would delay reliability improvements. Capital investments in the distribution system have already begun to deliver reliability benefits and will continue to provide these benefits as the

clearing cycle is ramped up. Capital investments in the distribution system should work in conjunction with increases in forestry work and are necessary to achieve reliability improvements.

Q. Do customers benefit from proactive reliability initiatives?

A. Yes. Vital proactive measures, including tree trimming and vegetation management, can significantly reduce outages and lessen damage from severe weather events. Trees are the greatest cause of interruptions of electric service for customers; mitigating these interruption threats will prevent against interrupted service for customers. As explained in greater detail in the testimony of Company witness Stewart, the Company continues to support a ramp-up to achieving a five-year clearing cycle on the Low Voltage Distribution ("LVD") system. In conjunction with the increase in line clearing, the Company will continue to invest in the distribution system to ensure reliability improvements expected by customers are realized and not delayed.

Q. Please describe the efforts of the Company to minimize customer costs for reliability improvements.

A. The Commission approved the Company's proposal to ramp up the line clearing cycle to five years. The ramp up of line clearing will occur over a five-year period reaching a steady-state by 2031. The Commission approved deferral of expense to a regulatory asset for amounts above the baseline line clearing expense. This has allowed for a $54.3 million reduction to expense included in this case and provides customers the benefit of spreading the recovery of this expense over a longer period.

Q. Has the Company proposed measures to further its commitment to the reliability and resiliency of the distribution system?

A. Yes. The Company is making proposals in this case that demonstrate its commitment to the reliability and resiliency of the distribution system. The Company is supporting continued efforts to achieve a five-year line clearing cycle, the scaling of undergrounding, wildfire mitigation, and the addition of Lines Reliability – High Voltage Distribution ("HVD") in the IRM.

Line Clearing

The Testimony of Company witness Stewart provides support for the Company's line clearing program. The Company strives for fewer tree-caused outages on its system, improving electric reliability for its customers in all conditions. To achieve this, the Company proposes to maintain a four-year clearing cycle for the HVD system and continue to ramp-up to a five-year clearing cycle for the LVD system as compared to the Company's previous goal of a seven-year cycle. The ramp up to a five-year cycle will occur through 2031 after which a steady-state cycle maintenance will begin to maintain the five-year cycle. The Company has carefully evaluated the costs and benefits of a shorter line clearing cycle and determined that a five-year cycle is the right approach to significantly improve electric reliability. As a result of the additional line clearing work, the Company anticipates a 27% reduction in tree caused outage incidents by 2031.

Undergrounding

One key element of increasing system resiliency is undergrounding of distribution lines. As explained by Company witnesses Duke and Partlan, the Commission approved 11.3 miles of undergrounding work that is supported by bridge period capital spending in this case. The Company is also supporting approximately 50 miles of undergrounding in

the test year of the case, with supporting business cases for each undergrounding project. Based on work completed by peer utilities, the Company expects an improvement in reliability of 90% or more. More miles need to be undergrounded to better align with the Company's peers on a percentage of system basis to provide customers with the resiliency benefits comparable to other similarly situated utilities.

Wildfire Risk Mitigation

The Company has utilized a third party to conduct a wildfire risk assessment to provide valuable information related to ignition risk, impact analysis, and benefit-cost analysis. This work identified areas of elevated wildfire risk in the state classifying it as very high risk, high risk, or moderate risk. Based on this information, the Company is including $1.8 million of test year capital spending in the test year for covered conductor and protective line devices. This work is supported by business cases inclusive of the risk and impact presented by the wildfire risk assessment.

IRM

As described later in this testimony, the Company's support and proposed continuation of the Commission-approved IRM reinforces the Company's commitment to distribution system reliability and resiliency. This proposed IRM includes an additional sub-program critical to customers and reliability. The Lines Reliability - HVD program requires sustained investment to address observed deterioration on the system and has a direct connection to system reliability improvements. The Company continues to face deterioration of many HVD assets, which threatens the reliability and resiliency of the distribution system. The inclusion of this program in the IRM shows the Company's commitment to ensuring the reliability and resiliency of the distribution system. The IRM

discourages the Company from shifting investment dollars away from these critical system investments and provides refunds to customers in the event of underspending.

Q. How do the proposals in this case support the Company's generation asset strategy and commitment to Michigan's clean energy transformation?

A. Company witnesses Mark E. Wittbrodt and Thomas P. Clark offer details about Consumers Energy's generation asset strategy and projected performance, planned investments in natural gas and battery energy storage systems. While this case does not request recovery of renewable energy related costs, Company witness Wittbrodt does discuss the impact of PA 235 of 2023 ("PA 235") on the future renewable energy portfolio indicating that the Company has filed a Renewable Energy Plan Amendment that provides a plan to comply with the renewable energy standards established in PA 235.

Q. Please describe recent events impacting the retirement of the Campbell plant.

A. On May 23, 2025, the U.S. Secretary of Energy issued Order No. 202-25-3 ("DOE Order") requiring Consumers Energy to continue operating the Campbell plant beyond May 31, 2025. Subsequently, the Secretary of Energy issued four additional emergency orders for 90 days each, the most recent of which requires continued operation of Campbell through August 16, 2026. The Company continues to coordinate with MISO and has complied with each DOE Order. The costs presented in this electric rate case include the continued recovery of the net book value of the Campbell plant as approved in Case No. U-21090. However, this electric rate case does not include any additional costs related to the impacts of any DOE Order. In January 2026, the Company filed a request at the Federal Energy Regulatory Commission ("FERC") seeking recovery of the net financial impact of complying with the May 2025 emergency order. FERC approval of this cost recovery

filing is pending. Any amounts recovered through the FERC cost recovery filing that have also been recovered through MPSC jurisdictional rates will be refunded to MPSC jurisdictional customers.

Customer Impacts

Q. Please quantify the overall rate increase if the Commission approves the entirety of the rate relief requested in this case.

A. Consumers Energy's rate request equates to an overall rate increase of 9.0% excluding the distribution deferral surcharge. The requested increase is 9.5% including the distribution deferral surcharge.

Q. What actions has the Company taken to mitigate the customer bill impacts of the investment plans described in this case?

A. We know that rising utility costs put real pressure on household budgets, especially for customers who are already struggling. That's why we're taking concrete steps to make rates more affordable for those who need help the most. The Company is proposing to increase our residential income assistance credit from $8.00 to $12.00 per month. This expanded credit is designed to provide meaningful relief for our most vulnerable customers. In addition, the Company's continued efforts to improve productivity and reduce costs will allow Consumers Energy to deliver on its necessary investments for customers and keep customer bills affordable.

Q. How will the Company's rate request affect the typical residential customer?

A. The Company expects that with the increase proposed in this case, the typical residential electric customer will pay on average about $5.10 a day for electricity during 2027. Residential customers receiving the income assistance credit will pay about $4.71 a day for

electricity during 2027. In his direct testimony, Company witness Michael C. Grondin explains the rate design details.

The Company understands that this increase will challenge some customers. Recognizing the challenges some customers face, the Company offers a range of assistance options, including the Consumers Affordable Resource for Energy Program, a Residential Income Assistance credit, and a Low-Income Assistance Credit for qualifying customers.

The Company and its employees are also contributors of both time and money to community based groups including the United Way, the Salvation Army, and many other local service organizations.

INTRODUCTION OF WITNESSES

Q. Please identify the other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.

A. The following witnesses will also be providing direct testimony on behalf of Consumers Energy in this filing:

- **Rachel R. Babale** supports the operational workforce resources necessary to support the capital investments and O&M spending in LVD and HVD.
- **Stacy H. Baker** supports the IT Departments, capital expenditures, and O&M expenses that are needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case. Ms. Baker also describes the Company's capital spending and O&M expenses related to cyber security operations and physical security.
- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing the overall rate of return. In addition, Mr. Bleckman provides additional support for short-term debt and projected cash balances.
- **Eugène M.J.A. Breuring** supports the Company's electric revenues, deliveries, generation requirements, and peak demand in the test year.
- **Ann E. Bulkley** supports the Company's proposed Return on Equity that should be used in computing the overall rate of return.

- **Thomas P. Clark** provides background, updates, and support for capital expenditures associated with new Battery Energy Storage System projects.

- **Laura M. Connolly** presents the Company's rate design proposals related to the Large Load tariff. She also addresses compliance items related to the Large Economic Development Rate.

- **Amy M. Conrad** describes the Company's overall compensation philosophy and provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP") at target levels.

- **Emily A. Davis** sponsors the Company's electric cost-of-service study that conforms to methods previously approved by the Commission. She also provides support for calculating the state reliability mechanism charge and substation ownership credit and the Electric Rate Case Deferral and IRM surcharges.

- **Jeffrey P. Dickey** supports the Company's projected and deferred service restoration spending. and the capital costs for the Control/Dispatch Center consolidation.

- **Emily M. Duke** provides an overview of the Company's electric distribution strategy and presents an overview of how the Company's distribution strategy has been developed and how it has evolved in recent years. Ms. Duke explains the strategic objectives that guide investment decisions. She also presents analysis related to wildfire mitigation, presents the Company's line loss study, and addresses certain issues related to advanced metering infrastructure.

- **Matthew J. Foster** supports the Company's Corporate Services O&M expense which includes uncollectible expense, and injuries and damages. Mr. Foster's testimony also supports Corporate Services Capital spending, IT projects supporting Corporate Services, and the request for certain accounting approvals.

- **Alex M. Gast** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Mr. Gast also supports the capital investment and O&M expense associated with executing this work. Mr. Gast also describes the Company's Demand Response ("DR") program's associated costs and proposed updates, and discusses the Transportation Electrification Plan.

- **Brittani A. Gray** presents the Company's proposed tariff language changes to its electric rate schedules.

- **Angel L. Green** supports the Company's requested recovery for EICP employee compensation costs. Ms. Green also discusses operational

performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.

- **Kendra K. Grob** supports the Company's costs related to retirement, health care, life insurance, long-term disability plans, and other benefits provided to its employees and retirees. Ms. Grob's testimony also supports continuation of the Defined Benefit Pension/Other Post-Employment Benefits Volatility Mechanism.

- **Michael C. Grondin** presents the Company's proposed rate design.

- **Quentin A. Guinn** describes the function and needs of the Company's facilities and supports proposed capital expenditures and O&M expenses related to the electric business portion of Facility Operations and Shared Services.

- **Joshua W. Hahn** supports PSCR costs expected during the test year and provides the Company's state reliability mechanism capacity charge inputs, cost offsets, demand, and reconciliation. Mr. Hahn also provides an update on Midcontinent Independent System Operator, Inc.'s Seasonal Adequacy Construct and supports the value of continued investment in the Company's generation assets and DR programs.

- **Joshua J. Judy** describes the function and needs of the Company's fleet services and supports the fleet investment.

- **Jon J. Koetje** presents actual 2025 decommissioning and coal ash disposal costs for D.E. Karn ("Karn") Units 1 and 2 and J. H. Campbell ("Campbell") Units 1, 2, and 3 and provides updated projected decommissioning expenses for Karn Units 1 and 2 and Campbell Units 1-3.

- **Kurt K. LaFrance** describes and provides the benefits of the Company's HVD lines system, HVD and LVD substations, Metro system, and System Protection assets, and supports the associated capital investments.

- **Scott A. McPhail** provides an overview of the Company's Grid Automation plans and supports the associated capital expenditures.

- **Jennifer M. Partlan** explains the Company's projected capital costs for the LVD system and the corresponding benefits of these investments.

- **Hannah L. Patton** presents the historical and test year revenue deficiency, including the treatment of various regulatory assets and liabilities. Ms. Patton also presents the projected test year revenue requirement for DR programs and requests related to distribution capital deferrals. In addition, Ms. Patton addresses deferrals related to the line clearing ramp-up and SAP S4/HANA, and presents the Company's proposal to recover the regulatory asset related to the March/April 2025 storm through a three-year amortization period.

- **Daniel A. Schmoekel** provides an overview of the Company's streetlighting assets and the strategic plan for management of those assets. Mr. Schmoekel also supports capital expenditures for streetlighting infrastructure. Mr. Schmoekel also discusses the Company's streetlight outage restoration performance.

- **Sara E. Stewart** provides an overview of the Company's line clearing program and recent progress of the program. Ms. Stewart also provides the strategy for the line clearing program and the reliability benefits. Finally, she provides expense requirements for the Line Clearing Program and discusses the resourcing plan for the program.

- **Brian J. VanBlarcum** supports the Company's property tax rate as well as the excess deferred federal income taxes being returned to electric customers because of the Tax Cuts and Jobs Act of 2017, the Company's Calculation C proceeding. Mr. VanBlarcum also supports two requested deferrals related to state income tax items.

- **Mark E. Wittbrodt** provides an overview of the Company's current generation assets and supports the Company's generation asset strategy including unit retirement dates and periodic outage plans, generation unit availability, capital expenditures, O&M expenses, employee retention program costs, and a description of environmental regulations for the Company's electric generating fleet. Mr. Wittbrodt also describes the evaluation of the long-term strategy for the river hydro facilities.

CASE REQUIREMENTS

Q. Has the Company addressed in this filing the requirements for its next electric rate filing included in the Commission's U-21870 Order?

A. Yes. The following is a list of requirements for Consumers Energy's next electric general rate application included in the U-21870 Order, with the Company witnesses who address the topics:

LVD New Business – The U-21870 Order included a requirement to provide an analysis of the difference in costs incurred for the LVD Lines New Business cost category between work performed in-house and work performed by contractors, and a description of what, if anything, the Company has done in response to bring more work in-house or vice versa. Company witness Partlan addresses this requirement.

LVD Reliability – The U-21870 Order included a requirement to provide additional detail for the LVD Lines Reliability Zonal Health Improvement cost category, showing the most cost-effective approaches to improving reliability and detailing the impact of the program. Company witness Partlan addresses this requirement.

LVD Lines Demand Failures – The U-21870 Order included a requirement to provide a review of the Company's capitalization policies and practices with respect to line inspections and security assessment work. Company witness Duke addresses this requirement.

Voltage Regulator Controllers – The U-21870 Order included a requirement for the Company to start tracking its inventory of voltage regulator controllers in comparison to the number of controllers installed and include this information beginning with its next electric rate case. Company witness McPhail addresses this requirement.

Benefit/Cost Analyses – The U-21870 Order included a requirement for the Company to update its benefit/cost analyses to include the full revenue requirement (i.e., full customer costs) in support of the Company's proposed distribution capital investments. This requirement is addressed by Company witnesses Duke, Partlan, and McPhail.

Distribution Expenditure Underspend – The U-21870 Order included a requirement for the Company to adequately justify any underspend in distribution expenditures and trace those dollars when they are spent, to the degree that it can, to ensure the Company spends approved dollars reasonably and prudently. Company witness Duke addresses this requirement.

Fleet Utilization – The U-21870 Order included a requirement to present a thorough plan that addresses the utilization of vehicles and field equipment and the impact of reduced

vehicle purchases in future years. The Order also included a requirement to include more details regarding existing vehicle usage by vehicle specification. Company witness Judy addresses these requirements.

Fleet Electrification – The U-21870 Order included a requirement to provide an assessment of the viability of using electric vehicles for all already-scheduled light-duty vehicle replacements between now and 2030. Company witness Judy addresses this requirement.

SAP S/4 HANA – The U-21870 Order included a requirement to include in future rate case filings until implementation of the SAP S/4 HANA project is complete any over- and under-recovery of each projected expense for the project compared to the 80% base (rough order of magnitude adjusted amount). Company witness Baker addresses this requirement.

Whole Home Optimization Demand Response Pilot – The U-21870 Order included a requirement to provide the Commission Staff with updates on the Whole Home Optimization DR Pilot in future electric rate cases and DR reconciliation cases and to notify the Commission Staff and intervenors in the instant case of significant changes in the approved plan. The Order also included a requirement to include more information about the specific technologies being tested for the Whole Home Optimization DR Pilot and how these technologies would be evaluated, and, to discuss the Company's intentions for any necessary transition or integration of the Whole Home Optimization DR Pilot participants once the pilot ends in 2028. Company witness Gast addresses this requirement.

Sales Forecast – The U-21870 Order included a requirement to provide additional detail pertaining to the calibration variables in its residential, commercial, and industrial

deliveries models and explain why the MetrixND model outputs are adjusted. This requirement is addressed by Company witness Breuring.

Forestry – The U-21870 Order included a requirement to present an analysis on the costs and benefits of removing 100% of tree canopy in the first zone. The Order also included a requirement to study the costs and benefits of moving to a four-year vegetation management cycle for the Company's low-voltage distribution system. These requirements are addressed by Company witness Stewart.

Emergent Reliability Funding – The U-21870 Order included a requirement to provide a detailed explanation of how expense associated with Emergent Reliability Funding is spent in each historical year. Company witness Wittbrodt addresses this requirement.

Corporate Membership Dues – The U-21870 Order included a requirement to file evidentiary support detailing its corporate membership dues expense and the specific customer benefits associated with that expense. Company witness Foster addresses this requirement.

Productivity –The U-21870 Order required the Company to provide details on its productivity offset that demonstrate measurable improvements and benefits for customers. Several witnesses address how the Company is using productivity gains to mitigate cost increases and benefit customers. I will also address this requirement later in my testimony.

AMI Cost Allocation – The U-21870 Order directed the Company to propose an alternative to how it allocates the costs of advanced metering infrastructure meters to customer classes to better reflect the system benefits these meters provide. Company witness Davis addresses this requirement.

Large Economic Development Rate – The U-21870 Order directed the Company to reconcile any overestimated revenue upon which it originally based the facilities allowance every five years and charge the Rate LED customer to make up any shortfalls. The Order also included a requirement to provide a proposal for a shortened discount term for new Large Economic Discount rate customers, similar to an intervenor proposal, as well as a proposal for the scenario in which the original basis for the rate approval is exhausted and there is a resulting capacity shortage. The Order also included a requirement to propose a power factor adjustment for the Large Economic Development rate that is sufficient to cover the cost of power factor correction on the Company's system. Company witness Connolly addresses these requirements.

Electric Heating/Heat Pump Rate – The U-21870 Order directed the Company to propose an electric heating/heat pump rate, considering various factors described in the order. Company witness Grondin addresses this requirement.

Service Connection Fees – The U-21870 Order directed the Company to create a fee structure for the overhead and underground service connection fees that covers fixed costs and that also reflects the variable costs. Company witnesses Gray and Partlan address this requirement.

Disconnection Policies and Reliability Metrics – The U-21870 Order directed the Company to reevaluate its disconnection policies and run additional regression analyses for the following reliability metrics: SAIDI with and without major event days, system average interruption frequency index ("SAIFI") with and without major event days, customer average interruption duration index with and without major event days, customers experiencing interruption duration of at least 5 hours, and customers

experiencing interruption duration of at least 24 hours. Company witnesses Duke and Gast address these requirements.

Geographic Information System – The U-21870 Order directed the Company to make continuous improvements to its Geographic Information System map regarding environmental justice reliability data that include, but are not limited to, a clear key explaining all acronyms and data categories and intuitive and navigable map controls. Company witness Duke addresses this requirement.

Reliability Improvements – The U-21870 Order directed the Company to demonstrate a clear link between reliability improvements and capital investments; assess cost-effectiveness, affordability, and the potential impacts of any SAIDI performance forecasts related to the June 12, 2025 order in Case No. U-21305; and provide alternative ways to evaluate system average interruption duration index performance. Company witness Duke addresses this requirement.

Cost of Service – The U-21870 Order directed the Company to provide empirical data in the Electric Asset Categorization report or other power system mapping to identify the extent to which higher voltage customers utilize and should pay for downstream assets. Company witnesses Davis and LaFrance address these requirements.

Customer Outreach – The U-21389 Order included a requirement to continue holding customer outreach events soon after the filing of an electric rate case. This outreach allows an opportunity for customers to provide feedback and provides customers with information on this filed rate case as well as customer assistance information. While not specified in the U-21870 Order, Consumers Energy will continue to hold these customer outreach events. The outreach event for this filing is scheduled for July 11, 2026 from 12 p.m. to 4

p.m. at the Washington Heights Community Carnival, 153 N. Wood Street, Battle Creek, Michigan 49037.

DISTRIBUTION IRM

Q. Is the Company proposing a Distribution IRM in this case?

A. Yes. The Company proposes to continue the use of the Distribution IRM. The Commission most recently approved a Distribution IRM in Case No. U-21870 covering the 12-months ending April 30, 2027. In this case, the Company is proposing an IRM that will cover a two-year period beginning May 1, 2027, consistent with the start of the test year of this case. Consumers Energy proposes to continue the IRM using the same investment categories approved by the Commission in Case No. U-21870 with the addition of the Lines Reliability – HVD program. Company witness Duke discusses these additional sub-programs in her direct testimony. Further, the Company proposes that the spending levels included in the IRM for the 12 months ending April 30, 2028 be set at test year levels approved for each program in this case and year 2 of the IRM should be equal to year 1 spending levels.

Q. What level of expenditures has the Company included in the IRM?

A. As further discussed in the testimony of Company witness Duke, the included expenditure levels are summarized in Table 2 below.

Table 2: IRM Expenditures

Sub-Program/ Investment Category	Proposed IRM Expenditures
Lines Reliability - LVD	$208,660,000
Lines Reliability - HVD	$83,617,000
System Protection	$4,672,000
Resiliency	$17,716,000
Total	**$314,665,000**

Q. How does the IRM provide customer and stakeholder benefits?

A. The Distribution IRM provides for the recovery of select distribution capital spending programs while providing for customer protections and additional opportunities for collaboration and review. The proposed IRM includes some of the investment programs that are critical for distribution system reliability. The previously approved IRM programs of Lines Reliability - LVD, Resiliency, and System Protection target improvements critical to reducing major event days. The Lines Reliability – HVD program includes the main HVD interventions to improve electric reliability and require sustained investment to address observed deterioration on the system. The IRM process, as discussed below, will provide customer protections and ensure the spending on these important programs is at approved levels to achieve the reliability benefits they support.

Q. Does the Company propose to use the same IRM process approved in Case No. U-21870?

A. The Company has one proposed modification to the IRM process. The process inclusive of the planning meetings, reporting metrics, and reconciliation process, as approved in Case No. U-21870, should be applied to the requested IRM in this case. However, the Company

proposes that the reconciliation of the IRM surcharge should not include how much revenue the surcharge collected from each customer class. Instead, the revenue requirement of any under spending would be refunded to customers based on the same allocation between classes as approved in this case. Reconciling IRM revenues by customer class adds an unnecessary complication to the reconciliation process.

Q. What benefits does the IRM process provide to customers?

A. The IRM and the associated process provide customer protections, transparency, collaboration, and increased accountability for distribution investments. Customers benefit from the certainty of investments in the capital programs included in the IRM that are critical to improved reliability. In addition, the reconciliation process will ensure customers do not pay to support investments if they are not actually made. The IRM brings additional transparency and accountability to project planning and results through reconciliation filings, collaboration on IRM project planning, and reporting on the execution of those plans. The distribution spending proposed for inclusion in the IRM represents commitment by the Company to the reliability and resiliency of the electric distribution system. The IRM ensures that approved spending on critical investments is spent on those investments. The reconciliation process for the IRM, by line item, provides a strong incentive for the Company to complete the IRM spending as included in the IRM surcharge and not shift dollars between programs.

Q. Please describe the proposed IRM surcharge for the 12 months ending April 30, 2028 and the 12 months ending April 30, 2029.

A. The calculation of the revenue requirement for the IRM, inclusive of the proposed increase in capital spending, is included in Exhibit A-166 (HJM-1). This annual revenue

requirement is then used by Company witness Davis to provide an allocation of the revenue requirement by rate class. Company witness Grondin then removes the IRM revenue requirement from the calculation of base rates to calculate the IRM surcharge by rate class for the test-year.

Q. How will base rates be impacted if the Commission adjusts the capital spending included in the IRM?

A. If the Commission adjusts the capital spending included in the IRM, base rates will need to be adjusted and designed to recover the revenue requirement of any capital spending not included in the IRM.

RIVER HYDRO DEFERRAL

Q. Is the future of the River Hydro facilities currently being addressed in separate FERC and MPSC proceedings?

A. Yes. As discussed by Company witness Wittbrodt, the Company has made filings with FERC and the MPSC (FERC Docket No. EC26-20-000 and MPSC Case No. U-21985) seeking approval for the FERC license transfer, sale of all 13 river hydro facilities, and associated power purchase agreement. These approvals are still pending at the time of the filing of this case. In the interim, the Company will continue to operate the hydro facilities in accordance with its FERC project licenses.

Q. Has the Commission addressed the uncertainty of the River Hydro facilities in a prior rate case?

A. Yes. In Case No. U-21585 the Commission approved the deferral of the revenue requirement of capital spending associated with the river hydros stating:

> The Commission finds that, due to the uncertainty of the disposition of the 13 river hydros as discussed by the parties, and rather than approve or disallow the capital expenditures

> that Consumers proposed in this rate case, the company may use deferred accounting of the revenue requirement on actual capitalized investments incurred subject to review in the Company's next rate case.

Continuation of this treatment was approved in Case No. U-21870. The Commission also approved the deferral of any hydro operating expense included in rates in excess of amounts actually incurred, with any such deferred operating expenses to be refunded to customers.

Q. Given the pending regulatory approvals related to River Hydro facilities, how does the Company propose to treat capital and O&M expense in this case?

A. The Company proposes the continued use of deferred regulatory accounting through the test year of this case for the revenue requirement on actual capital spending incurred related to the River Hydros. As a result, the Company has removed the rate base impact associated with the 2024 and 2025 historical capital spending and has not included any projected capital spending in this case. O&M expense needed to safely operate the hydro units has been included in the case. If actual O&M expense is lower than amounts included in rates, the Company proposes to defer the difference to a regulatory liability for refund to customers. The continuation of this treatment of the capital and O&M related to the River Hydros will provide the time needed to determine the future of the River Hydros while ensuring that customers are not asked to pay for investments or operating expenses that are not actually incurred.

PRODUCTIVITY OFFSETS TO INFLATION

Q. The Commission, in its order in Case No. U-21870, directed the Company to provide details on its productivity offset that demonstrate measurable improvements and benefits for its customers. Has the Company taken steps to offset inflationary cost increases through productivity improvements?

A. Yes. The Company continuously implements initiatives such as process automation, workforce optimization, and strategic sourcing to reduce costs and improve efficiency. These efforts help keep customer rates lower than they otherwise would be while maintaining and improving reliability and safety.

Q. Has the Company presented evidence to demonstrate the efforts that the Company is taking to offset inflation with productivity increases?

A. Yes. The Company provides measurable evidence of productivity improvements that help offset inflationary pressures and reduce costs for customers. These improvements often manifest through process efficiencies, technology integration, and workforce optimization, enabling the Company to deliver more value at the same or lower cost. While productivity does not always appear as a direct dollar reduction, and may not be quantified in a way that could be itemized by line item in witness exhibits, it frequently results in avoided cost increases and improved service delivery without additional resources. Examples include:

- IT contractor resources: Projected O&M costs are approximately $2.3 million lower as a result of achieved efficiencies. See the direct testimony of Company witness Baker.
- Voltage Regulator Controllers: Purchasing of materials the year prior to planned deployment in this capital program has helped avoid some inflationary

pressures. In addition, costs savings of approximately $1.5 million were gained from the use of a competitive bid process for construction labor. See the direct testimony of Company witness McPhail.

- Streetlight Conversion: A proactive plan to convert HID cobrahead streetlights and post top located in the vicinity of failed cobrahead streetlights and post top to LED resulting in $597,000 in savings related to reduced truck rolls and it is anticipated that there will be $136,400 in savings annually. These savings have been built into the case. See the direct testimony of Company witness Schmoekel.

Productivity savings are reflected in the Company's forecasted costs and help offset inflationary pressures, ultimately benefiting customers by keeping rates lower than they otherwise would be.

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for $456 million in annual rate relief, and collection of $25 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2026. Consistent with Consumers Energy's commitment to provide exceptional value and service to every customer, caring for the communities where we live and work, and delivering on investor expectations, the Company is requesting revenue recovery for infrastructure investments that primarily support the Clean Energy Plan, the Reliability Roadmap, as well as other programs, including the distribution IRM, that will benefit customers. In addition, the Company is proposing an increase to the low-income credit from $8.00 to $12.00 per month in support of our most vulnerable customers. The Company is also continuing its

efforts to minimize the increase in O&M expense through productivity improvements, first time quality, and reducing employee safety incidents. Consumers Energy is committed to customer value and improving customer service and this filing is a representation of the commitment put forth in the Company's purpose – World Class Performance Delivering Hometown Service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

RACHEL R. BABALE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Rachel R. Babale, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Labor & Employee Relations.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Arts in Social Relations from Michigan State University and a Master's Degree in Human Resources and Labor Relations from Michigan State University. I joined Consumers Energy in 2015 as a Senior Human Resources Consultant in the Labor Relations Department. I then became the Manager of Labor Relations. In 2021, I became the Director of Labor Relations. In 2025, the scope of my department grew to include leading the People Delivery, Employee Relations, Employee Services, Talent Acquisition, and People Strategy teams within Human Resources. Prior to working for Consumers Energy, I was a Field Examiner for the National Labor Relations Board in Baltimore, MD.

Q. What are your responsibilities as Executive Director of Labor & Employee Relations?

A. My responsibility as Executive Director of Labor & Employee Relations is to provide direction to six key functions within the Human Resources department, including Labor Relations, Employee Services, Payroll, Talent Acquisition, Employee Relations, and People Strategy. Of the functions, Labor Relations and Talent Acquisition is most relevant to this testimony.

These two functions partner to lead and/or execute the plan for the operational resourcing requirements.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide support for Consumers Energy's projected capital investments and Operating and Maintenance ("O&M") spending in Low Voltage Distribution ("LVD") and High Voltage Distribution ("HVD") with respect to operational resources.

First, I will discuss Consumers Energy's resource needs. Second, I will discuss the Company's resource planning approach, including use of a cross-functional resource planning review process, the importance of leveraging both Company and contracted resources, and the ability of the Company to adequately use our talent pipeline to ensure resource adequacy.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-30 (RRB-1)	Summary of Historical Year, Bridge Period, and Projected Test Year for Operations Resources – Electric LVD Workplan; and
Exhibit A-31 (RRB -2)	Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources – Electric HVD Workplan.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. How does Consumers Energy plan for the workforce required to deliver the Reliability Roadmap, as presented by Company witness Emily M. Duke, and how will it meet these resourcing demands?

A. The Company's requirement for its operational workforce is analyzed using a cross-functional resource planning process that focuses on one to five years of future resource needs.

This proactive plan development provides visibility into any resource gaps and adequate time to address those gaps. It also focuses on developing Company resources in a way to provide greater value to the customer by reducing safety risks and developing workforce skills within the Company. These continuously advancing skills are key to the success of the investment work outlined in the Reliability Roadmap, as sponsored by Company witness Duke as Exhibit A-95 (EMD-11). By executing the plan with a highly trained and safety-minded workforce, the Company will ultimately produce a more reliable and resilient grid.

The Company meets its resourcing demands as follows: first, the Company effectively and efficiently scales its workforce capacity to meet its operational workplans, inclusive of its Utility Workers Union of America ("UWUA") and contract workforces. The Company has demonstrated its ability to scale its workforce capacity from 2019 through 2025. Total apprentices in the Electric Lines Program have grown from 135 in 2019, to 230 in 2025. During that same period, the number of qualified journey line workers in Electric Operations grew from 470 in August 2019, to 637 in December 2025. This growth in the workforce has increased the Company's capacity to deliver work focused on meeting customer needs for a reliable and resilient grid.

Our planning process constantly evaluates the need for workforce capacity adjustments consistent with the Company's efforts to maintain and improve the electric distribution system. Second, direct hiring and apprentice programs play a key and sustainable part in the Company's approach to secure operational resources and must be commensurately scaled and funded.

Q. Please describe the Company's Electric Lines Apprenticeship Program.

A. It takes four years of training and on-the-job experience to train a journey line worker. The length of time required to train a journey line worker means the Company must have a strong, future-facing workforce plan. As apprentices advance in the Company's program, they can apply various new skills, based on where they would fall in the four steps of the apprenticeship program. In Step I of their apprenticeship, they acquire skills in climbing and can work on energized secondary, string power lines between poles, sagging of conductor, and streetlighting. In Step II of their apprenticeship, they acquire the technical ability to test equipment, install transformers, frame and set poles, and build power banks. In Step III of their apprenticeship, they acquire the skills to conduct work on single phase energized primary, protective equipment, and perform switching. During Step IV of their apprenticeship, they acquire the skillset to install line equipment, remove line equipment, work energized primary climbing, and work multi-phase energized primary. As they advance in the apprenticeship program, they acquire the skills to perform the above tasks safely, and with direct oversight from qualified journeymen, in addition to a joint oversite committee partnered between the Company and UWUA. Each subsequent level of apprentice provides a higher level of value to customers as many of them are focused on reliability-based projects that pertain to their specific skill level.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW OF RESOURCE NEEDS

II. RESOURCING APPROACH

I. OVERVIEW OF RESOURCE NEEDS

Q. What are the Electric Operations resources needed to complete the electric distribution workplan?

A. The Company will need to increase both its LVD and HVD Field Maintenance and Construction resources beyond 2026 levels to complete the electric distribution workplan. The change in operational resource needs are as follows:

	2026	2027	2028
LVD	1,306	1,468	1,497
HVD	386	466	425
Total Resources	1,692	1,934	1,922
Growth Percentage (YOY)		**14%**	**0%**

The projected resources are needed to complete the distribution workplan as described by Company witnesses Jennifer M. Partlan (LVD Capital), Kurt K. LaFrance (HVD Capital & Metro), Emily M. Duke (Distribution Policy & O&M), and Scott A. McPhail (Grid Automation). The costs associated with these resources are sponsored by Company witness Duke and are summarized in Exhibits A-94 (EMD-10), and A-87 (EMD-3).

Q. How are the projected resource needs determined in Exhibits A-30 (RRB-1) and A-31 (RRB-2)?

A. Resource needs are determined by reviewing the various work types, applying historical data using reasonable expectations (historic times for completion of specific work types),

and identifying the funding and qualified resource needs required to complete the work plan each year.

II. RESOURCING APPROACH

Q. What is the Company's approach to identifying its resource needs?

A. The Company uses a cross-functional resource planning process that brings visibility to current and future resource needs, and enables the ability to ensure sufficient resources are available at the right times to meet demand. By evaluating future resource requirements, the Company can make sure essential workplans are achievable and plans are in place to fill any identified gaps through appropriate countermeasures.

Resource needs are determined based on the level of investment in programs such as Demand Failures, New Business, Reliability, Capacity, and Asset Relocation. These resource needs are translated into work hours needed to support the entire workplan. When gaps are identified, the planning team works together to identify countermeasures and prioritize the workplan. Employee safety, customer experience, and efficient use of resources are each part of the balanced approach that drives the mix of countermeasures selected.

Longer-term choices, such as adding apprentices, are the result of long-term work plan projections, and improve our capability to deliver in the future as demands increase, such as those outlined in the Reliability Roadmap.

The Company is taking proactive measures to increase its capability to execute the Reliability Roadmap. These measures include direct hiring and apprenticeships as well as contractor networks, each with an emphasis on building scalable and effective local workforces. Various skilled resources are needed for Electric Operations, including LVD

line workers, HVD line workers, electric underground line workers, electric field lab employees, substation operators and maintenance personnel, and grid management personnel. The Company is exploring alternative resourcing strategies that enable resources to be deployed quickly. First, in December of 2024, the Company began direct hiring of qualified Journey Line Workers. Overall efforts were positive, resulting in hiring 20 qualified workers onboarded in 2024. An additional 31 Journey Line Workers were hired in 2025. Recruiting efforts for 2026 resources began in the fall of 2025 to ensure resources can be onboarded for the test year of the case, resulting in 8 Journey Line Workers currently on track for onboarding in 2026. To enhance recruitment efforts, the Company plans to engage with a search firm to identify qualified Journey Line Workers seeking a career move. Marketing materials will be updated to highlight the benefits of working at Consumers Energy. Social media and radio advertising will be used as well.

Securing the workforce needed to do this work is a vital part of the Company's ability to achieve the improved reliability that the Reliability Roadmap is meant to deliver. The Company intends to secure the additional labor resources needed to achieve the plan and will continue to move toward these increased workforce goals.

A. LVD Maintenance and Construction

Q. How many LVD workers does the Company currently utilize?

A. As of December 31, 2025, the Company uses 1,189 LVD field workers to complete LVD maintenance and construction work. In addition, the Company has divided the state into four zones with contracts competitively bid and awarded to provide contractor support for each zone. Furthermore, the four zone contractors and numerous additional contractors may participate in specific bids or provide resources for ongoing workload, where

additional resources are needed for specific project work or to balance internal crewing capacity.

Q. How many LVD workers does the Company anticipate needing for the projected test year?

A. The Company anticipates needing 1,479 workers to complete the work in the projected test year as shown in Exhibit A-30 (RRB-1), which provides an overview of the Company's operational resource needs for the LVD workplan.

Contractor resources will flex up or down to complement the work being performed by our internal crews. Contractor resources may also be flexed up or down based on the nature of the work being performed or based on the availability of our crews relative to the total workplan.

Q. How does the Company determine the number of resources that are needed to complete distribution workplans?

A. Workforce needs are determined by historical workplans, projected capital and O&M, and estimated attrition levels.

Q. How does the Company build and maintain the LVD and Underground workforces required to complete the planned distribution work?

A. The Company negotiated contractual agreements with the UWUA in 2025 to hire 48 apprentices through the 5-year contract. The hiring of additional apprentices aligned with current attrition rates and projected workplans to build a correctly sized LVD workforce. The Company is direct-hiring skilled LVD workers, as well as using apprenticeship programs with community colleges, a Veterans Hiring Program, and the UWUA. The Company has expanded its work with additional community colleges, allowing an

extended reach into communities, targeting increased diversity and a long-term reduction of internal transfers by virtue of initially hiring employees into the regions they want to live in long term.

Consumers Energy has collaborated with five community colleges to offer the EMPOWER Pre-Apprentice Line Worker Training Program. Jackson College, Mott Community College, Alpena Community College, Grand Rapids Community College, and Lansing Community College have been instrumental in the Company's ability to maintain a steady influx of line workers, supplying roughly 79% of the workforce needed in that role since 2019.

B. HVD Maintenance and Construction

Q. What workforce does the Company utilize to perform HVD line work?

A. The Company uses a contractor workforce to complete HVD line maintenance, construction, and restoration via a competitive bidding process. In addition, the primary HVD contractors and numerous additional contractors may participate in specific bids for more complex HVD project work.

The Company works closely with its primary HVD contractors to ensure awareness and visibility into the workplan to ensure cost effectiveness, stability, and growth of the HVD workforce as needed to support the plan. HVD line contractors are only approved to work on the HVD side of lines, with the exception of restoration activities, where LVD restoration is needed.

Q. What workforce does the Company utilize to perform HVD substation work?

A. The level of complexity of HVD substation work, along with the optimized planned use of resources, drives the decision making for which workforce to use for substation work.

Maintenance work, emergent repairs, and short-cycle planned work are often completed by Company employees in the HVD Substation Maintenance group. A competitive bid process is used for engaging dedicated resources or part-time contractors for influxes of work or within planned specific projects.

Q. What are the Company's HVD workforce needs for the projected test year?

A. Exhibit A-31 (RRB-2) provides an overview of the Company's operational resource needs for the HVD workplan.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. How long have you worked for Consumers Energy Company ("Consumers Energy" or the "Company") and what positions have you held?

A. I have worked for the Company for over 25 years in various individual contributor and leadership positions. The first nine years were in the Finance Department as an Accounting Analyst performing responsibilities to support Payroll and Accounts Payable and later as the Payroll Manager during the Systems, Applications, and Products in Data Processing ("SAP") implementation. Thereafter, I moved to the Information Technology ("IT") Department where I have held a number of positions including Enterprise Resource Planning ("ERP") Portfolio Manager, Director of Business Relationship Management – Corporate Services, and Executive Director of IT Business Technology – Corporate Services. In these roles I focused on technology supporting corporate areas of the Company and had IT departmental responsibility for the delivery and operation of IT applications for Finance, Human Resources ("HR"), Supply Chain, Legal and Government, Regulatory & Public Affairs. I am currently the Director of Technology Portfolio Office responsible for portfolio management of the Company's IT, Security, and Operational Technology ("OT") assets, project management office including agile services, project delivery organization, technology vendor management, and technology change enablement. This includes the management of the IT long-term financial plan, administration of portfolio management, development of testimony and exhibits, and supporting rate cases for the IT Department.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science in Business Administration degree from Central Michigan University in December 1992 with a major in Accounting.

Q. Have you ever testified in any other proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I testified in the following cases:

- Case No. U-21308 – 2022 Gas Rate Case;
- Case No. U-21490 – 2023 Gas Rate Case;
- Case No. U-21806 – 2024 Gas Rate Case;
- Case No. U-21870 – 2025 Electric Rate Case; and
- Case No. U-21981 – 2025 Gas Rate Case.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to describe the Operating and Maintenance ("O&M") expenses and capital expenditures needed by the IT Department to maintain and secure existing IT and security systems and enable new capabilities and services to support safety, reliability, and resiliency. I also provide an overview of increasing threats in both Cyber Security and Physical Security areas, their evolution over time, and the changing regulatory landscape that necessitates increased O&M funding. These increases are essential for advancing cloud computing solutions, maturing security capabilities, and protecting the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Company's plans for deterring threats before they impact the Company and its customers, detecting

malicious activity, and recovering quickly with minimal impact while complying with all regulations.

The benefits of increasing technology use for customers, and the Department's support of the Company's commitments outlined in the Integrated Resource Plan ("IRP") and Electric Distribution Infrastructure Investment Plan ("EDIIP"), will also be highlighted. Lastly, the importance of achieving full recovery of the requested expenses and expenditures to provide the best value to the Company's customers will be demonstrated.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

- The importance to customers of digital investments and the role of IT to build and support those investments.
- Increasing and evolving cyber and physical threats.
- Leveraging increased cloud capabilities.
- Support for Operational O&M expense funding.
- A description of the investment, both O&M and capital, needed to keep the Company's systems secure, current, stable, and supporting new capabilities.
- Definition and rationale for the use of reduced Rough Order of Magnitude ("ROM") estimates and explanation of the difference from contingency requests.
- An explanation of the projects included in this rate case filing for the IT Department and their supporting business plans, as described in Exhibits A-20 (SHB-5) and Exhibit A-22 (SHB-7).
- Company action to address previous Commission concerns, including:
    - Company total one time project cost across multiple years;
    - Total Company cost of ownership of each project beyond initial one-time project investment;

- Recurring hard savings over the life of the investment; and
- Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS").

- Individual project synopses and requests to support electric and customer plans.
- Further information about and justification of several larger and more complex electric and customer projects for which projected spending varies from amounts forecasted in the previous electric rate case, Case No. U-21870, including the following projects:
  - Catastrophic Crewing (CatCrew) Version 2.0;
  - Electric Geographic Information System ("GIS") Utility Network Transformation; and
  - Ransomware Recovery-OT-Electric & Generation.
- Further information on the actual and projected costs for projects which had disallowances in Case No. U-21870:
  - Product Family Enhancements-Customer-Capital for the Web Chat AI enhancement;
- Further information to address concerns raised by the Commission Staff ("Staff") in the past related to the website redesign project.
- Individual project synopses and requests to support corporate functions crucial to running an efficient business.
- Individual IT project synopses with supporting detailed exhibits for the Application Currency projects and the Asset Refresh Program ("ARP") projects.
- Further information about and justification of several Application Currency projects for which projected spending varies from amounts forecasted in the previous electric rate case, Case No. U-21870, including the following projects:
- Individual IT project synopses with a supporting, detailed exhibit (Exhibit A-27 (SHB-12)) for Enhancement projects including explanation of the changes to how enhancement costs projections are supported based on a three-year historical average.
- Explanation of the changes to ARP-Cyber Security, subdividing it into the following new ARP projects relevant to this case:
  - ARP-Cyber-Common; and

- ARP-Cyber-Electric.

- Explanation of the changes to ARP-Local Area Network ("LAN"), ARP-InfoBlox, and ARP-OT Electric, consolidating them into the following new ARP projects:
  - ARP-Network-Common; and
  - ARP-Network-Electric.

- Further information to address concerns raised by Staff in the past related to lack of information provided by the Company regarding the method used to calculate the total projected costs for new purchases for ARP-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM").

- Further information about and justification, of several Asset Refresh Program projects for which projected spending varies from amounts forecasted in the previous electric rate case, Case No. U-21870, including the following projects.
  - ARP-Collaboration;
  - ARP-FDAM;
  - ARP-Infoblox Refresh;
  - ARP-Server and Storage; and
  - ARP-WAM.

- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects.

- Further information about and justification, of several larger and more complex IT/Digital Foundations and Capabilities projects for which projected spending varies from amounts forecasted in the previous electric rate case, Case No. U-21870, including the following projects:
  - Data & Analytics Platform Rationalization;
  - Digital-Hybrid Cloud and Data Center Migration;
  - SAP High-performance ANalytic Appliance ("HANA") Database Migration; and
  - Security/OT Field Modernization.

- Further information to address concerns raised by Staff in the past related to benefit and need of the OT Data Center Migration project.

- Further information about and justification of the complex SAP S/4HANA Implementation project.

- Explanation of the reason for confidential treatment information related to the SAP S/4HANA Implementation project and explanation of Confidential Exhibits A-21 (SHB-6), A-23 (SHB-8), A-28 (SHB-13), and A-29 (SHB-14).

- Individual IT project synopses for the Security projects.

- Further information about and justification of a larger and more complex Security project for which projected spending varies from amounts forecasted in the previous electric rate case, Case No. U-21870, including the following projects:

  - Critical Substation Upgrade; and

  - Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-17 (SHB-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2025 and Test Year 12 Months ending April 30, 2028;
Exhibit A-18 (SHB-2)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2025 - 13-month balance ending December 31, 2025, and for the projected years 2027 – 13-month balance ending April 30, 2028;

Exhibit A-19 (SHB-3)	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2025 and Test Year 12 Months ending April 30, 2028;
Exhibit A-12 (SHB-4), Schedule B-5.5	Projected Capital Expenditures Information Technology Summary of Actual and Projected Electric and Common Capital Expenditures;
Exhibit A-20 (SHB-5)	Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses for the Years 2025, 2026, 2027, and 2028;
Confidential Exhibit A-21 (SHB-6)	Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Projected Electric & Common Capital Expenditures and O&M Expenses for the Years 2026, 2027, and 2028 for the SAP S/4HANA Implementation Project;
Exhibit A-22 (SHB-7)	Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects;
Confidential Exhibit A-23 (SHB-8)	Business Case Executive Summary for Bridge Period and Test Year for the SAP S/4HANA Implementation project;

Exhibit A-24 (SHB-9)	Asset Refresh Programs Projected Electric and Common Capital Expenditures, For the Projected Year 2027 and Test Year ending April 30, 2028, and For the Historical and Projected Years 2025 and 2026;
Exhibit A-25 (SHB-10)	ARP-FDAM and ARP-WAM New Purchases Four-Year Historical Average;
Confidential Exhibit A-26 (SHB-11)	Application Currency Programs Projected Electric and Common Capital and O&M Expenditures for the Years 2027, 2028, and Test Year 12 Months ending April 30, 2028;
Exhibit A-27 (SHB-12)	Enhancements Three-Year Historical Average;
Confidential Exhibit A-28 (SHB-13)	Projected 13-Month Average of IT S/4HANA Regulatory Asset for the projected years 2027 – 13-month balance ending April 30, 2028; and
Confidential Exhibit A-29 (SHB-14)	Projected SAP S/4HANA Implementation Project Reconciliation for Case Nos. U-21870 and U-22070.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

DESCRIPTION OF THE IT DEPARTMENT

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to consistently provide and maintain reliable, secure, simple, and intuitive digital solutions and services that support the delivery of business

objectives, including execution of the Company's IRP and EDIIP. Inherent in those objectives are the Company's goals to provide exceptional service to its customers by supplying safe, reliable, affordable, clean, and equitable energy.

The IT Department strives to find the appropriate balance of value and cost in digital solutions. The Company's evolving and pragmatic approach to digital solutions supports many best practices, including:

- Executing work in an efficient and effective manner while remaining flexible as deliverables change by adopting agile frameworks, platforms, and product centric operating models that allow the Company to adjust to changing demands on the IT system;
- Equipping coworkers with digital skills through training that enables them to deliver business value faster to ensure the Company meets customer expectations;
- Moving to cloud solutions where and when appropriate to reduce cost, improve security, and increase the speed of providing new capabilities;
- Treating data as an asset and deploying analytics on a larger scale for effective decision making, optimization of existing assets, and efficient investment prioritization;
- Deployment of a consistent asset management system and integrated control systems to reduce risk, optimize and digitize processes, and monitor the health of the system to identify necessary preventative maintenance that reduces waste and long-term costs;
- Ensuring customer data is safe and secure, their privacy is protected, and both critical technology assets as well as critical infrastructure assets are secure; and
- Managing security risks and mitigating associated threats.

Q. Please describe the functions the IT Department performs.

A. The IT Department provides reliable, secure, and simple digital solutions and services to the Company's customers and internal business units. This includes identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure and analytics to support

customer safety and reliability. The IT Department also provides the day-to-day operational support for coworkers using technology, whether that technology is a desktop, laptop, or mobile device (e.g., ruggedized field device, tablet computer, cell phone, smartphone, or other handheld device).

The scope of the IT Department also includes operational technology ("OT"). OT is the set of real-time industrial control systems that monitor and control the Company's critical electric infrastructure, such as the Electric Supervisory Control and Data Acquisition ("SCADA") systems.

Additionally, the scope of the IT Department includes Security. This includes emergency management, physical security, and cyber security. Security exists to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat is successful in causing impact, and comply with all governmental and industry regulations. Security sets standards based on external threats and guides security work required by the IT and OT teams.

Q. How does technology support the Company's electric plans?

A. Technology is an integral part of all aspects of the Company's electric strategy from generation all the way to the customer. The Company is leading a clean energy transformation while increasing electric reliability and resiliency for customers. To realize this plan, the Company needs to invest in new technology as the future of energy generation is increasingly more distributed and complex. As the Company increases investment in demand response, energy efficiency, and grid modernization tools, these "virtual power plants" will help the Company reduce energy demand and manage customer load efficiently and effectively. The continued addition of solar energy sources, wind energy

sources, and battery storage to the generation landscape will also require the utilization of technology systems to operate and manage them safely, effectively, and efficiently.

The Company's EDIIP is its roadmap to reliability that is driven by investments in a modern distribution system to safely deliver clean, affordable, and reliable power to customers throughout Michigan with a goal of fewer and shorter power outages. The Company's plan for a reliable and resilient modern electric grid requires technologies to support the electric devices, communications, and analytics for advanced capabilities like Volt-VAR Optimization and Conservation Voltage Reduction that advance energy efficiency and peak demand reduction. The Company's plan also relies on technology to enhance electric reliability and resiliency through Fault Location, Isolation, and Service Restoration, as well as enabling initiatives for Distributed Energy Resources, like solar and wind generation, and energy storage systems.

The use of technology is also essential to establishing data analysis techniques to understand, communicate, and engage with the Company's customers in a meaningful way; connecting with customers using their channel of choice; enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-service" through digital channels; providing customers accurate, timely energy bills, and consistent payment processes; and offering options for customers to understand their energy consumption.

Q. What are some of the biggest challenges the IT Department currently faces?

A. A big challenge the IT Department currently faces is the integration and implementation of emerging technologies, data, and analytics needed to achieve the Company's goals described in the IRP and EDIIP. The Company relies heavily on accurate data and high performing systems that can handle higher transactions and data volumes. Customers

depend on these same systems to report outages, receive timely information on the estimated time of restoration, and view the outage map including impacted areas. It is important that the Company achieve full recovery of requested expenses and expenditures to keep these systems updated with the latest security and maintenance patches while delivering new capabilities to help restore customers faster.

Another challenge is that security continues to be a significant risk area and challenge for utilities. Traditional physical security issues of protecting publicly accessible, geographically dispersed critical infrastructure are and will continue to be exacerbated as resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, ransom extortion, denial of service, and critical infrastructure attacks. For example, a February 7, 2024 Cybersecurity Advisory from the Cybersecurity and Infrastructure Security Agency ("CISA") states that the CISA, National Security Agency, and Federal Bureau of Investigation assess that People's Republic of China ("PRC") state-sponsored cyber actors are seeking to pre-position themselves on IT networks for disruptive or destructive cyberattacks against U.S. critical infrastructure in the event of a major crisis or conflict with the United States.[1] The U.S. authoring agencies have confirmed that the PRC state-sponsored cyber group known as Volt Typhoon has compromised the IT environments of multiple critical infrastructure organizations - primarily in Communications, Energy, Transportation Systems, and Water and Wastewater Systems Sectors - in the continental and non-continental United States and its territories, including Guam.

[1] Available at sophos-state-of-ransomware-2025.pdf

While cyber security is no longer a new area, each year impacts from cyber security incidents increase. According to a 2025 Sophos report, which provides comprehensive insights into attack trends, exploited vulnerabilities remain the most common technical root cause for the third consecutive year, with ransomware involved in 32% of incidents. Over a three-year span (2023-2025), the average total cost of recovery was approximately $2.03 million, while the average ransom payment was around $1.13 million. The Company must protect against data breaches and threats to critical infrastructure. In light of increasing global geopolitical tensions and federal warnings about potential cyberattacks targeting critical infrastructure—particularly from Russia and China—it is imperative that the Company proactively safeguards against data breaches and threats to essential systems. Compliance with federal and state regulations such as Transportation Security Administration ("TSA") security directives and American Petroleum Institute standard 1164 v2 is crucial, as failure to adhere may result in significant penalties. In this environment, utility security teams must be fully prepared with comprehensive strategies that prioritize the protection of customer data, ensure regulatory compliance, uphold privacy standards, and secure the infrastructure that supports the Company's operations and customers.

Q. Please further explain the current environment with respect to cyber threats facing utility companies.

A. Cyber threats are increasing. The most glaring example is ransomware as discussed above. These threats have increased, not only in their impact but also their level of sophistication. Criminal groups are profiting on ransomware, and it has become such a lucrative business that they now conduct cyberattacks in a more sophisticated manner with teams of people

who focus on an individual target. Such groups are more focused on Fortune 500 companies because of the potential for large ransom payments.

The Progress Software "MoveIT" extortion event demonstrates this increase in sophistication. A zero-day vulnerability (a flaw in a system or device that is unknown and does not have a fix available to correct the flaw, rendering the system vulnerable) was used to compromise the data of hundreds of MoveIT customers across all industries. The ability to exploit zero-day vulnerabilities has historically only been within reach of nation-state actors, not criminal groups. The amount of money being made has allowed these groups to invest in finding such vulnerabilities and dramatically increased their capabilities. The Company sees, on average, several hundred cyber security events daily. This volume demands a robust security program with various layers of defense. No single tool, person, or process can protect the Company's assets 100% of the time; therefore, the Company must rely on multiple lines of defense to meet these challenges.

Beyond ransomware, nation-state actors have a strong interest in United States critical infrastructure. The federal government has repeatedly called out this risk and has been imploring critical infrastructure owners to increase their capabilities. On July 28, 2021, the Biden Administration released a memo titled "National Security Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems" ("July 28 Memo").[2] The implications of the National Security Memo are clear.

First, the threat to critical infrastructure is real and no longer theoretical. Even the Company has seen intrusion attempts from nation-state level actors. The July 28 Memo provided that "[t]he cybersecurity threats posed to the systems that control and operate the

[2] Available at https://bidenwhitehouse.archives.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/.

critical infrastructure on which we all depend are among the most significant and growing issues confronting our Nation."

Second, cyber security of critical infrastructure is a national security issue and priority. The July 28 Memo explained that "[t]he degradation, destruction, or malfunction of systems that control this infrastructure could cause significant harm to the national and economic security of the United States." Utilities have had strong cyber security programs, and the Company is no different. However, by calling out cyber security of critical infrastructure as a national security issue, the Biden Administration signaled that the Company, as an owner of critical infrastructure, should meet an even higher standard moving forward. The National Security Memo suggested that utilities need to have capabilities matching those of the top government agencies and contractors. This increased expectation will take time to develop and increased funding to achieve.

Third, as ordered by the Biden Administration, the CISA has established Cross Sector Cybersecurity Performance Goals, which remain effective under the current administration and are intended to be a baseline set of cybersecurity practices broadly applicable across critical infrastructure.[3] These Performance Goals signal the federal government's interest in gaining further assurances that owners and operators of critical infrastructure are meeting the expectations set forth in the memo. The Company expects this to include new, mandatory regulatory standards for electric.

The current administration also recently issued an executive order suggesting that it may shift responsibility for investments in cybersecurity and other critical infrastructure to state and local governments. In doing so, the White House recognized that "[c]itizens

[3] The Performance Goals are available at Cross-Sector Cybersecurity Performance Goals | CISA.

are the immediate beneficiaries of sound local decisions and investments designed to address risks, including cyber-attacks, wildfires, hurricanes, and space weather."[4] Thus, the White House continues to support further investment in cybersecurity, even if state and local governments are ultimately asked to assume more responsibility. The executive order directed federal officials to reevaluate national critical infrastructure policy, including several National Security memorandums, but the July 28 Memo was not on the list of memorandums being reviewed.

Q. Please describe how physical threats are increasing or evolving.

A. Cyber security receives much of the national headlines because it is a relatively new risk and does not require physical proximity to execute an attack. However, physical security risks are still extremely relevant in the critical infrastructure space, and they continue to evolve. In the past few years, there have been several incidents that pose risks to the stability of the electric grid. These include theft, equipment damage, vandalism, and intentional gunfire aimed at disrupting the grid.

- **Copper Theft**: Thieves target substations, transformers, and other electrical infrastructure due to the high resale value of copper, which causes substantial damage and disrupts power supply.
- **Transformer Damage**: Damaged transformers can leak oil, posing environmental hazards. Tampering with high-voltage equipment can also lead to explosions or fires.
- **Gunfire Incidents**: In the mid-Michigan area, there have been incidents where gunfire was aimed at critical electric infrastructure, intending to disrupt service.
- **Threats to Employees and Facilities:** Increase in threats to employees and facilities endangers employee safety and can disrupt operations needed to maintain a reliable service.

[4] Presidential Actions, *Achieving Efficiency Through State and Local Preparedness*, THE WHITE HOUSE (March 29, 2025), https://www.whitehouse.gov/presidential-actions/2025/03/achieving-efficiency-through-state-and-local-preparedness/.

These types of incidents present challenges in maintaining a reliable and safe electricity supply.

Q. What physical security challenges are you experiencing in securing critical infrastructure assets?

A. The very nature of certain utility assets makes them very challenging to secure. Large assets such as a headquarters building or power plants can be secured using traditional physical security measures such as video cameras, card access, fencing, locks, keys, gates, and guards. The smaller, more distributed assets are significantly more challenging to secure. Placing guards at each asset would be untenable from a cost perspective. Technology solutions have historically been challenging because of limited feature sets (enhancements and capabilities) and network capacity at many of these remote locations. These limitations have led utilities to implement basic physical protections and accept remaining risk. Responses to security issues in these environments are, therefore, reactive and have become insufficient. These factors have made these critical assets soft targets to those who would do harm intentionally and attractive for opportunistic crimes. A shift to a more proactive approach will minimize the impacts to customers from outage, safety, and cost perspectives. The Company continues to be proactive in its approach to better protect its assets and increasing safety.

Q. What is changing in the regulatory landscape?

A. The current cyber and physical regulatory landscape is highly uncertain. The current administration aims to reduce regulatory oversight, but their position on cyber and physical security and its national security implications remains unclear. The recent executive order indicates that the administration may propose more state control over these areas.

Regardless, the Company anticipates a continued push for more cyber incident reporting and mandatory standards in electric distribution, whether driven by federal or state authorities. The industry is expecting additional mandatory cyber security standards across the regulatory landscape.

Q. Has the work required to meet cyber security regulations and requirements increased in recent years?

A. Yes. The current and emerging cyber-attack trends are evolving, and the number of threats are increasing, in impact and sophistication as described earlier in my direct testimony. As the security industry best practices evolve, security requirements change, and new regulations, such as North American Electric Reliability Corporation/Critical Infrastructure Protection ("NERC/CIP") requirements for electric systems and TSA security directives and American Petroleum Institute standard 1164 v2 also affect the Company's corporate systems, which are a part of this case. The IT Department must strive to keep pace with the time and expense of retrofitting existing infrastructure and applications to maintain compliance and an appropriate security posture.

Q. Do cyber security requirements increase the frequency of IT patching and upgrades?

A. Yes. To address changing security threats and vulnerabilities, vendors regularly release security fixes or "patches" to their products. The increased volume of threats to digital assets heightens the need to keep systems current, and timely security patching is a key control for any security program. Technology vendors establish timelines for versions of their product they no longer support or no longer provide security updates or patches for. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security

requirements. Patching analysis, patch application, and patch tracking activities are all considered IT Operations O&M expenses. The Company focuses on mitigating exposure to "Known Exploited Vulnerabilities" that the Cybersecurity and Infrastructure Security Agency has confirmed have been used to breach other companies' IT systems in the past. Reducing vulnerabilities requires timely patching, as well as upgrades and replacements to IT software and systems. The operational expenses related to security are important for the protection of Company assets and customer information.

Q. Please explain why the Company is proposing to use more Software as a Service ("SaaS") based products.

A. SaaS based offerings are often the only option for certain technology services/vendors. For those that do also have on-premise options, many are stating that they will not be updated as quickly or may lack certain capabilities of their cloud counterparts. Vendors are making this shift for many reasons. First, as technology moves more and more to the cloud, security services need to adapt as well. Second, vendors can much more quickly build new capabilities for customers in a cloud-based scenario where they control all the underlying hardware and infrastructure. Finally, the massive scale of security data requires much more flexibility which the cloud offers, and on-premise options do not.

In addition to the industry drivers, there are benefits to both the Company and customers. More SaaS means fewer large capital outlays for large hardware purchases, vendor integrations, and less asset refresh cost. The Company anticipates fewer large capital projects in its future year planning for cyber security as capital requests have reduced, while physical security requests are increasing. Finally, using SaaS allows the

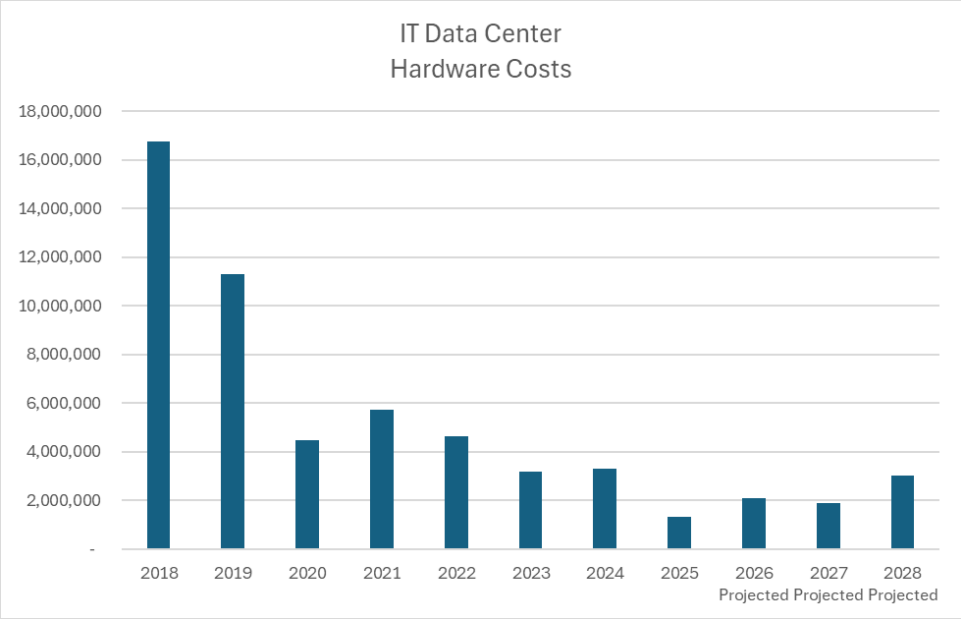
Company to receive the best security capability available and allows vendors to adapt to changes much more quickly than on-premise solutions.

Q. Is the Company migrating to the cloud and what are the advantages of leveraging increased cloud capabilities?

A. Yes, the Company is migrating most of its IT data center to cloud-based services. Leveraging increased cloud capabilities offers several advantages, including the ability to scale capacity, pay only for resources that are used, avoid capital investment and O&M expense for hardware and maintenance, enhance security, and employ built-in backup and recovery solutions.

First, cloud capabilities offer scalability, enabling the Company to easily adjust their computing resources based on demand. This allows the Company to increase or decrease capacity as needed, unlike traditional data centers that would require longer implementation times. For example, during peak periods like storm response, the Company can quickly scale up resources to handle increased traffic. Conversely, during off-peak periods, cloud resources can be reduced to optimize costs.

Second, cloud capabilities also offer cost efficiencies by only paying for the resources that are used. It reduces the Company's capital expenditures in physical hardware and the associated ongoing maintenance costs, as well as the cost of a physical location. The Digital-Hybrid Cloud and Data Center Migration project, which began in 2022, has enabled the Company to avoid the capital investment for IT data center hardware asset refresh based on a five- to seven-year refresh cycle, as shown in the table below. This initiative includes migrating or retiring applications out of existing Company and co-location data centers into cloud services.



Third, cloud capabilities offer advance security features and regular updates to protect sensitive data, ensuring compliance with industry standards and regulations.

Fourth, the Company's owned data center is aging and beginning to have challenges with operational stability. Moving to the cloud allows the Company to avoid the large capital expense of building a new data center.

Finally, cloud capabilities offer reliable backup and disaster recovery solutions through redundant infrastructure to ensure high availability and reliability, minimizing downtime and providing consistent access to services.

Q. How does the Company prioritize, balance, and manage the delivery of new capabilities that support the IRP and EDIIP with operational work that includes meeting the security requirements described above?

A. The Company's critical security and operational fixes are given priority over new capabilities to ensure safe, secure, and reliable operation of its digital assets. There is a high demand for new and enhanced technology capabilities across the Company. New investments are prioritized based on an evaluation of the benefits, costs, customer value,

and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects are approved through the Company's budget and rate case processes and ultimately implemented.

Q. What business categories has the Company defined in the IT Organization?

A. The Company has defined the following business categories in the IT Department supporting the IRP, EDIIP, and customer offerings in this case: (1) Electric; (2) Electric & Gas Shared; (3) Corporate; (4) Customer; (5) IT/Digital Foundation; and (6) Security. These business categories are used to group investment spending in my exhibits to better connect rate case filings with the Company's plans. I will describe each of the business categories later in my testimony.

IT OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS

Q. What is IT Operations O&M expense for IT?

A. The Company uses IT Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services. IT Operations O&M expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and application or appliance support through managed services contracts. Software and cloud solution vendors typically increase these fixed costs on an annual basis. Variable costs include labor for equipment monitoring, break/fix activity, maintenance activity, disaster recovery, security improvements, software patching, and cloud usage

costs. Operations costs also include physical security site assessments, vulnerability and penetration test remediation, additional guard support, system break/fix or maintenance activity, privacy program maturity, staffing support to meet emerging regulatory laws and regulations, and additional security system improvements. The activities associated with the fixed and variable costs are required to keep the Company's digital, information, and physical assets protected and performing at sufficient levels. The Company's customers benefit from the system stability and reliability that result from the activities funded by IT Operations O&M expense. These activities include emergency response, 24/7 billing, payment and usage services, contact center support, new service installations, and various other digital offerings, as well as physical and cyber security activities. Any unrecovered IT Operations O&M cannot be recovered in future rate case filings, which is why any disallowance could impede the Company's ability to maintain and secure its facilities and systems.

Q. Please describe the operational work required to keep information and physical assets protected from cyber threats.

A. There is a variety of operational work required to keep information and physical assets protected from cyber threats. First, regarding information assets, security tools must be kept functional when they are called on to protect the technology vital to serving the Company's customers. This technology includes software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are in place in the event of a cyber intrusion. Third, as described previously, systems must be patched on a regular basis in accordance with security requirements. Vendors regularly

release security updates that must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations when deployed. Fourth, as cyber security standards and requirements change, IT teams must implement the appropriate corresponding technical changes on existing systems to ensure Company assets remain secure. These requirements evolve and adapt as threats change in our environment. Security regularly reviews and updates physical and cyber security standards to maintain the appropriate posture with various industry frameworks, as well as compliance with cyber security regulations. This includes the technical requirements for IT to follow, which increases operational costs while continuing to best protect Company assets.

Regarding physical assets and employee safety, first, routine assessments must be performed on all assets and facilities to ensure proper maintenance is performed and security protections are properly placed including perimeter protection, cameras, and card readers for facility access. Second, additional security support is needed for employees when threats are present near field project work, storm restoration activities, or Company sponsored public events or forums. Third, additional security guard support is needed at facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats of violence against the Company, increased protest activity as seen in 2020, increased contractor traffic, and potential employee issues) to ensure the safety of employees and any visitors to the Company's facilities.

Q. What value will customers receive for the projected test year O&M expenses?

A. Foundational technologies, such as infrastructure, user devices, and collaboration tools, play a crucial role in supporting the systems that deliver services to the Company's customers.

Infrastructure includes physical and virtual systems that support all Company operations. These systems are essential for running critical applications, managing data, and maintaining communication that ensure efficient and reliable service to customers. User devices provide workers access to real-time data, help manage work, and facilitate communication to serve customers. Collaboration tools enable workers to collaborate effectively, address issues efficiently, and share information to serve customers.

Further, foundational technology systems support predictive analytics and machine learning algorithms that can forecast demand and identify potential issues before they become critical, allowing for proactive maintenance and response. Additionally, these systems support the integration of renewable energy sources, enabling a more sustainable energy supply.

Customers are required to provide certain types of data as part of the service provided to them and want to know that the Company has a world-class cyber security program working to protect data provided. Data breaches can cause identity theft, fraudulent charges, and time lost addressing related associated impacts. Beyond data breaches, customers also expect their data to be handled properly and only for the purposes intended. The discipline which addresses these concerns is broadly referred to as privacy, which is also within the corporate responsibility of the IT Department. In addition to data-related concerns, customers expect the Company's core services to be available 24/7. This is relevant on both the corporate and operational sides of the business. A ransomware attack would limit the service the Company can provide to customers and could lead to delays in resolving issues, obtaining service, outages, or significant safety concerns. An attack against the Company's operational systems could lead to a protracted loss of

electricity or natural gas service for large portions of the service territory. Interruption of gas or electric service due to a cyberattack is not acceptable, and customers expect the utility to have all the protections necessary to ensure this does not occur.

In addition, physical security measures are essential in protecting the infrastructure that delivers electricity. This includes securing substations, power plants, and transmission lines from physical threats such as vandalism, theft, and natural disasters. Implementing robust physical security protocols, such as surveillance systems, access control, and perimeter security, helps safeguard these critical assets. By integrating physical security with technological systems, the Company can create a comprehensive approach to protecting the electrical grid and ensuring uninterrupted service to its customers.

Together, these foundational technologies and cyber and physical security measures ensure that electric is delivered efficiently, reliably, and safely to customers.

Q. Please describe Exhibit A-17 (SHB-1).

A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Year 2025 and 12 months ending April 30, 2028. Page 1 summarizes the electric allocation of actual and projected IT Department operational expenses. Specifically:

- Column (a) provides the IT Operations O&M expense category;
- Column (b) identifies the total 2025 historical IT Operations O&M expense as $59,376,000;
- Column (c) identifies the Test Year projected IT Operations O&M expense as $73,741,000; and
- "Labor" line items include employee labor and indirect labor; "Material" line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; "Contractor" line items include outside services, hardware and software licenses and maintenance, and software subscriptions and "Non-Labor Overheads" line items include non-labor related overheads, chargebacks, and loadings; "Non-Labor Other" line items include employee training, wireless plans, and supplies.

Page 2 presents the amounts of the projected IT Operations O&M expenses that were developed by applying an inflation rate to the historical O&M expense. Specifically:

- Column (a) describes the categorical expense;
- Column (b) provides the historical IT Operations O&M expense;
- Column (c) calculates the projected inflation increases to the historical O&M amounts;
- Columns (d) includes the scope/cost increases net of productivity gains; and
- Column (e) provides the Test Year projected IT Operations O&M and is the sum of columns (b), (c), and (d).

Q. Please describe the Scope/Cost Increases Net of Productivity Gains in Exhibit A-17 (SHB-1), page 2, column (d).

A. IT does not apply inflation in all categorical spend projections for IT Operations O&M expense. Labor is the only categorical spend projection that includes a merit increase based on the inflation rate. Inflation is not used to project any other categorical spend projections for IT Operations O&M expense. Future contractor expenses reflect current commitments to increase payments under existing contracts, as well as the addition of new contracts needed for ongoing and new project work taking place before or during the test year. Material and Non-labor Other are projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies.

Q. Please describe the projected IT Department IT Operations O&M expense for the test year, as reflected in Exhibit A-17 (SHB-1).

A. The projected IT Operations O&M expense for the test year is $73,741,000, comprised of $60,320,000 for IT and $13,421,000 for Security, representing an increase over 2025 historical costs of $59,376,000. The reason the Company is projecting an increase in the test year is the necessity to fund continued investment in programs to sustain and improve

customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT from 2025 to the test year include: (1) net labor increase ($2.0 million) due to insourcing data & analytics, cloud resources, corporate applications, and merit increases offset by other resource efficiencies; (2) increase in materials ($0.6 million) for line sensor support; (3) increase in contracts costs ($11.3 million) primarily due to Infrastructure as a Service and Platform as a Service costs due to the migration of applications to the cloud as a result of the Digital-Hybrid Cloud and Data Center Migration and SAP HANA Database Migration projects; increases in other cloud subscriptions and license and maintenance agreements, such as IT Service Management; and increase in productivity tools to support automation offset by other subscription and license and maintenance agreements efficiencies; (4) reduction in contractor resources ($2.3 million) due to efficiencies; and (5) reduction in Non-Labor Other costs ($0.5 million).

Known increases that are projected for Security from 2025 to the test year include: (1) labor increase ($0.2 million) based on merit increases offset by resource efficiencies; and (2) increase in contractor costs for cloud subscriptions and license and maintenance agreements ($2.6 million) due to migrating applications to the cloud, multi-factor authentication, and risk management offset by other cost optimization efforts to minimize increases.

Q. What does the Company's IT Operations O&M expense include?

A. As described earlier, IT Operations O&M expense is made up of several components, such as labor, business expenses, material costs, contractor support, and vendor licensing and maintenance contracts.

"Labor" includes operational and governance costs for the IT employees who perform activities such as maintaining and supporting capital assets; disaster recovery and business continuity planning and testing; cyber security analysis and mitigation, such as security patching; and implementing performance measures to control IT costs and ensure compliance. These activities are variable and dependent on the outcome of risk analyses and other factors.

"Non-Labor Other" includes costs such as business expense, employee training, wireless plans, and supplies. These costs are variable and dependent on the needs of the organization.

"Material" includes costs such as individual computer peripherals, tools, supplies, and replacing failed components such as hard drives. These costs are variable and dependent on the needs of the organization.

"Contractor" are costs of managed services and third parties that maintain and operate the Company's IT assets. Similar to "Labor," the activities include system monitoring, system break/fix, disaster recovery activities, system analysis, and patching. The use of third parties to maintain and operate the Company's IT assets provides value by helping to control labor costs, offering up to 24/7/365 support, and providing increased access to specialized IT expertise.

"Contracts," including "On-Premise Contracts" and "Cloud Subscriptions," reflect the Company's IT operations expenses for contracts with vendors who provide infrastructure as a service, platform as a service, cloud subscriptions, software and hardware licensing, support, and maintenance services so systems remain safe from mechanical and software failures and cyber intrusions. Lapses in licensing, support, or

maintenance coverage caused by financial constraints would expose the Company to unfavorable security and operational risks or issues.

The Company relies heavily on vendors and their products to run the utility's digital systems and, as a result, the number of contracts and the corresponding costs are a significant piece of the total IT Operations costs.

Q. Is the method used by the Company to project IT Operations O&M an accurate and prudent approach?

A. Yes, the method used by the Company to project IT Operations O&M expenses in Exhibit A-17 (SHB-1) is the most accurate method. The Company's approach uses a detailed analysis of known fixed and variable expenses for the test year. These include increases that result from new investments and assets tied to growth in digital, new cyber security regulations and requirements, and outcomes of cost optimization efforts. By using known and expected expenses that are coupled with the evolving digital landscape, the projection is the best representation of the Company's required IT Operations O&M expenses in the test year.

Q. Please describe Exhibit A-18 (SHB-2).

A. Exhibit A-18 (SHB-2) is the IT Cloud Computing Prepaid Balance for Electric and Common operations for the historical 13 months ended December 31, 2025 and the projected 13 months ending April 30, 2028. It provides a summary of the electric allocation of actual and projected IT Department operational expenditures. Specifically:

- Column (a) provides the prepaid balance category;
- Columns (b) through (n) provide each month's ending IT cloud computing prepaid balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Exhibit A-18 (SHB-2).

A. The move to utilize cloud computing is resulting in an increase in prepaids associated with cloud computing subscriptions and implementation costs. The Company has identified cloud computing as a viable alternative for several technology solutions, which are described in more detail for the associated projects below. To support the adoption of cloud computing, the Company is adjusting working capital to reflect projections for cloud computing subscriptions and implementation costs. Cloud computing costs are projected based on existing cloud computing subscription agreements plus projected new cloud computing costs based on planned implementations.

Q. Please explain why the monthly balances in Exhibit A-18 (SHB-2), page 1, are negative and the monthly balances on page 2 are positive.

A. The IT Cloud Computing Prepaid Balance reflects amounts paid in advance for cloud subscriptions and related services. Exhibit A-18 (SHB-2), page 1, shows the historical 13-month balances as negative to back out actual prepaid balances from the working capital starting point so they can be replaced with projected balances. Page 2 shows the projected 13-month average as positive to add the projected prepaid balance to working capital. Prepaid balances decline as services are consumed but are also replenished through ongoing purchases and renewals. This working capital adjustment is provided by Company witness Hannah L. Patton on Exhibit A-12 (HLP-34), Schedule B-4.

IT INVESTMENTS O&M EXPENSES—MAINTAIN A CURRENT SYSTEM AND BUILD NEW CAPABILITIES

Q. How is IT Investments O&M for IT used by the Company?

A. IT Investments O&M is used by the Company to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide new capabilities for internal business units, security operations, and customers.

Q. Please describe the importance of upgrading IT systems for cyber security requirements and operational stability.

A. Upgrading applications, appliances, operating systems, database management systems, and security devices, such as cameras and card readers, are essential to delivering safe, reliable, affordable, clean, and equitable electricity to the Company's customers. Implementing current versions of technology enables the Company to operate secure and stable systems, remediate security vulnerabilities, keep customer and Company data secure, maintain vendor support, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What cyber security risks could occur if the Company does not keep its systems upgraded?

A. Technologies and security devices that are not upgraded are often no longer supported by vendors, which increases security risk as well as system operations risk, as security patches are regularly released by vendors based on known vulnerabilities. Security patches are typically not produced for products no longer supported by the vendor, referred to as end-of-life products; therefore, an end-of-life product may have known vulnerabilities and no method to remediate the risk. This increases the risk of a significant cyber event impacting Company operations, data, and services to its customers.

Q. How does the Company determine which systems need to be upgraded?

A. While the Company's preferred upgrade strategy is to stay, at most, one version behind the vendor's currently available version, the Company considers multiple factors to determine when upgrades are needed. These include application criticality to business and customer operations, severity of existing vulnerabilities and operational risk, operational impacts of performing the upgrade, ability to defer, resource availability, organizational change impact, and cost. Deferring an application upgrade for too long has the potential to increase the overall cost of the upgrade since the larger number of differences between versions generally adds complexity and cost to an upgrade effort.

Until recently, the Company has lacked funds to maintain and keep systems current. This led to technical obsolescence, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue might not be remediated or mitigated, which would cause direct impact to Company operations, its customers, or both. The Company prioritizes operational support over new investments when resources are limited, thus putting the IRP and EDIIP at risk when important systems cannot be kept current with available resources.

Q. Please describe Exhibit A-19 (SHB-3).

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Year 2025 and the 12 months ending April 30, 2028. Page 1 provides a summary of the electric allocation of actual and projected IT Investments O&M expenditures. Specifically:

- Column (a) provides the IT Investments O&M expense category;
- Column (b) identifies the 2025 historical IT Investments O&M expense as $8,512,000;

- Column (c) identifies the Test Year projected IT Investments O&M expense as $11,616,000;

- For Investments Planning expense, "Labor" line items include employee labor, and "Contractor" line items include outside services; and

- For Investments expense, "Labor" line items include employee labor and indirect labor; "Material" line items include hardware purchases and maintenance costs; "Non-Labor Overheads" line items include non-labor related overheads, chargebacks, and loadings; "Non-Labor Other" line items include employee training and business expenses.

Page 2 presents the amounts of the projected IT Investments O&M expenses that were developed by applying an inflation rate to historical O&M expense. Specifically:

- Column (a) is a description of the categorical expense;

- Column (b) provides the historical IT Investments O&M expense;

- Column (c) calculates the projected inflation increases to the historical O&M amounts;

- Column (d) includes the scope/cost increases net of productivity gains; and

- Column (e) provides the Test Year projected IT Investments O&M and is the sum of columns (b), (c), and (d).

Q. Please describe the Scope/Cost Increases Net of Productivity Gains indicated in Exhibit A-19 (SHB-3), page 2, column (d).

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection of $640,000 for IT and $9,000 for Security is for anticipated decreases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the EDIIP, IRP, and other Company long-term plans. Inflation is also not used to project future IT Investments O&M expense. The projections for IT Investments O&M expense of $9,415,000 for IT and $1,537,000 for Security are based solely on expected project costs

for the test year as compared to the historical period, as detailed later in my testimony and in Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6).

Q. Are the preliminary project stage activities that must be part of IT Investments O&M expense per Financial Accounting Standards Board ("FASB") guidelines important in technology investment projects?

A. Yes. The preliminary project stage activities are essential to ensure the Company makes prudent investments in technology that benefits customers. The activities cover much of the work included in the Company's investment planning for IT projects. Investment planning activities gather information that is required by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT.

Q. Is the investment planning activity speculative?

A. No, it is not speculative. Investment planning is a pragmatic process that results in documented technology investment details. The process documentation includes: a project description and description of system functionality, project timelines including expected implementation date and spending plans, project benefits, a description of alternatives considered and rationale behind the decision, and cost benefit ratio, which were required by the MPSC in Case No. U-18238. Other important activities of investment planning are: identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

During the investment planning phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment. As an example, to maintain the reliability and safety of the Company's field dispatch communications, the Company needed to replace the aging core radio system infrastructure. The Company spent time on up-front planning for the 800 MHz Modernization upgrade project to build and confirm the scope, estimates, and alternatives. Investment planning is time needed to better understand the vendor solution and organize the work. Investment planning is based on key outcomes and fact-gathering to ensure it is not merely speculative.

Q. Should the Company be allowed recovery for the planning expense tied to technology investments?

A. Yes, the Company should be allowed recovery for this up-front planning activity. This work is required by the MPSC for technology investment, and for good reason. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure potential investments provide sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant investment planning. Critical as these expenses are, the Company does strive to minimize planning expenses; only those potential investments with the highest expected value even reach the planning phase. This reasonable and prudent work has associated costs and is required by the MPSC for technology investment planning. Accordingly, the Company should receive recovery for this required expense.

Q. Would it be more accurate to use a different method to project the Company's IT Investments O&M expenses?

A. No. The level of IT Investments O&M expense is closely coupled with the projected capital expenditures for IT and the upgrade and replacement cycles for existing assets. To fully and appropriately execute plans to spend the capital that has been deemed prudent to deliver value to its customers, keep its technology assets as current and secure as reasonably possible, and adhere to the FASB ASC 350-40 guideline for project activities that should be expensed, the Company requires the specific and forward-looking IT Investments O&M requested for the Test Year period. Other methods such as a historical average, which would be lower than the requested amount in this case, would not allow the Company to keep its systems current for security and reliability or to make necessary and prudent capital expenditures to achieve the outcomes of the IRP and EDIIP and improve customer service. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of IT Investments O&M than projects in earlier years.

INVESTMENTS CAPITAL EXPENDITURES

Q. Please describe the capital expenditures shown on Exhibit A-12 (SHB-4), Schedule B-5.5.

A. Exhibit A-12 (SHB-4), Schedule B-5.5, identifies the electric allocation of actual and projected capital expenditures to procure, install, and implement the software and infrastructure described in my testimony to meet business requirements. Specifically:

- Column (a) provides the business category designation for the capital expenditures:
  - Corporate;
  - Customer;

- Electric;
- Electric & Gas Shared;
- IT/Digital Foundation; and
- Security.

- Page 1 of 2
  - Column (b) identifies the 2025 historical year capital expenditures as $37,036,000;
  - Column (c) identifies the 12 months ending December 31, 2026 projected bridge capital expenditures as $82,391,000;
  - Column (d) identifies the 4 months ending April 30, 2027 projected bridge year capital expenditures as $31,396,000;
  - Column (e) identifies the 16 months ending April 30, 2027 projected bridge year capital expenditures as 113,788,000; and
  - Column (f) identifies the 12 months ending April 30, 2028 projected test year capital expenditures of $58,700,000.
- Page 2 of 2
  - Column (b) identifies the 4 months ended April 30, 2026 capital expenditures as $18,623,000;
  - Column (c) identifies the 12 months ending April 30, 2027 capital expenditures as $95,165,000;
  - Column (d) identifies the 12 months ending April 30, 2028 projected bridge year capital expenditures as $58,700,000; and
  - Column (e) identifies the 28 months ending April 30, 2028 projected bridge year capital expenditures as $172,488,000.
- For Investments expenditures, "Labor" line items include employee labor; "Software" line items include software licenses and maintenance contracts; "Material" line items include hardware purchases and maintenance contracts; "Contractor" line items include staff augmentation, managed services, and other contracted services; "Non-Labor Overhead" line items include overheads; and "Non-Labor Other" line items include pension expense, administrative/general expense, Allowance For Funds Used During Construction ("AFUDC"), and business expenses.

Q. Please explain Exhibit A-20 (SHB-5).

A. Exhibit A-20 (SHB-5) identifies the electric allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in my testimony to meet business requirements. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the IT Department. Specifically, within this exhibit:

- Column (a) provides the year of spending for each line item project;
- Column (b) identifies the project name associated with each line item capital and O&M expenditure for the applicable year or years;
- Column (c) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (d) identifies the Business Category or Product Line of the project;
- Column (e) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (f) identifies the project's start date;
- Column (g) identifies the project's end date;
- Column (h) provides the project's cost/benefit ratio;
- Column (i) provides the total Company expected project capital costs;
- Column (j) provides the total Company expected projected O&M costs;
- Column (k) identifies the project's estimate type;
- Column (l) provides the project's electric portion total capital expenditure for the applicable year or years;
- Columns (m) through (r) provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year or years broken down by:
    - Software costs (m);

- Material costs (n);
- Labor costs (o);
- Contractor costs (p);
- Non-Labor Overhead costs (q); and
- Non-Labor Other costs (r).

- Column (s) provides the project's electric portion total O&M spend for the applicable year; and
- Columns (t) through (y) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year or years by the following categories:
  - Software costs (t);
  - Material costs (u);
  - Labor costs (v);
  - Contractor costs (w);
  - Non-Labor Overhead costs (x); and
  - Non-Labor Other costs (y).

Q. Please explain Confidential Exhibit A-21 (SHB-6).

A. Confidential Exhibit A-21 (SHB-6) is structured identically to Exhibit A-20 (SHB-5), however it is specific to the SAP S/4HANA Implementation project.

Q. Please explain the difference between Exhibit A-12 (SHB-4), Schedule B-5.5, compared to Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6).

A. Exhibit A-12 (SHB-4), Schedule B-5.5, Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6) are each capital expenditure exhibits that display different views to address the different requirements of the MPSC, as well as the IT Department, as outlined below:

- Exhibit A-12 (SHB-4), Schedule B-5.5, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and

- Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6) are more comprehensive exhibits displaying the detail of each project over the four-year time periods of 2025, 2026, 2027, and 2028.

Q. Please explain Exhibit A-22 (SHB-7).

A. Exhibit A-22 (SHB-7) is an Executive Summary report generated from the Company's internal BPS. This exhibit provides the approved business case information for each IT project in Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6). Exhibit A-22 (SHB-7) addresses the Commission's interest in:

- projects having approved business cases;
- total project cost for multi-year projects;
- associated hard savings; and
- benefit-cost overall value utilized by the Company.

This exhibit provides the same view the Company uses internally to review the Executive Summary of each business case approved to be included in the test year. It also outlines the total Company cost of ownership of each project, including the initial one-time project investment which could fund work occurring over multiple years, and the projected ongoing support costs after project implementation. Additionally, it identifies recurring hard savings over the life of the investment and provides the cost benefit ratio with a zero breakeven point calculated by the Company's internal BPS. Specifically, within each section of this exhibit:

- Header Information section includes project name, the date the report was generated, and BPS identification number. Specifically:
  - o Project Name is the name of the project that indicates the project objective;
  - o Report Pulled is the date the Executive Summary report was generated from BPS; and

- Item ID is the unique identifier from BPS.

- Basic Information section includes work category, work type, alias, brief description, portfolio, organization, business unit, and department. Specifically:
  - Work Category identifies classification of work and activities based on the Company methodology;
  - Work Type identifies "project" as the type of work for all IT investments;
  - Alias identifies historical project names for reference;
  - Description identifies a brief description of the project's intent and the expected outcome;
  - Portfolio identifies the financial planning portfolio for whom the work will be performed;
  - Org identifies the financial planning organization for whom the work will be budgeted;
  - Business Unit identifies the business unit for whom the work will be budgeted; and
  - Dept identifies the department for whom the work will be budgeted.
- Work Objectives includes a synopsis of the project, including the problem statement; objectives; information on project scope, functionality, and benefits; and alternatives considered. Specifically:
  - Problem Statement provides an explanation of the problem(s) the work addresses;
  - Objectives provides information about the business value the project will deliver;
  - Scope describes the high-level business functionality and a list of high-level project deliverables; and
  - Alternatives provide a summary of each of the alternatives considered, why each alternative was not selected and the rationale behind the alternative selected.

- Dates section includes the projected implementation phase start or end dates for projects, with the exception of the Annual Spend Programs such as Asset Refresh Programs, Application Currency, and Enhancements. Specifically:
  - Initiation is the start date of the project Plan phase;
  - Project Plan & Scope Definition is the end date of the project Plan phase;
  - Final Engineering, Planning & Design is the end date of the Design phase;
  - Execution is the end date of the Execute phase;
  - In-Service/Go-Live is the project's implementation date; and
  - Closeout is the end date of the Close phase.
- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
  - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
    - Cap+COR is the total of all the capital expenditures; and
    - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
  - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
    - Labor includes the internal staffing costs for project implementation;
    - Outside Services includes the external labor and services for project implementation;
    - Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and AFUDC;
    - Employee Benefits includes costs for employee benefits;
    - Material includes costs for hardware purchases;
    - Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and

- Other includes miscellaneous costs.

- Value & Impacts Summary Section provides a summary of the projected cost and benefits, risk and other value associated with a project for Capital expenditures and O&M expense, including ongoing maintenance, where:
  - For purposes of O&M:
    - Reduction includes the hard O&M savings;
    - Initial includes the implementation and ongoing maintenance costs;
    - Incremental includes any other O&M costs; and
    - Net is the difference of the reduction, initial, and incremental O&M costs.
  - For purposes of Cap+COR:
    - Reduction includes any hard capital savings;
    - Initial includes the implementation costs;
    - Incremental includes any other capital costs; and
    - Net is the difference of the reduction, initial, and incremental capital costs.
  - For purposes of Revenue:
    - Reduction includes any expenses;
    - Initial includes implementation revenue;
    - Incremental includes any increase in revenue; and
    - Net is the difference of the reduction, initial, and incremental revenue.
  - For purposes of determining financial value of a project, the B/C Ratio (Overall), as shown in the figure below, is the net present value of the change in O&M, plus change in Capital, plus change in Revenue, divided by Total Cost of Ownership set with a breakeven point at zero.

$$\textit{Financial Value}\ (F_{Overall}) = \frac{\sum B}{\sum C} - 1$$

Where
B = Benefits
C = Total Costs

- For purposes of identifying risk:
  - Type of Corporate Risk;
  - Level of impact;
  - Likelihood of risk; and
  - Description of risk.
- And, for purposes of identifying other value:
  - Type of other value; and
  - Description of other value.

Q. Please explain Confidential Exhibit A-23 (SHB-8).

A. Confidential Exhibit A-23 (SHB-8) is structured identically to Exhibit A-22 (SHB-7), however it is specific to the SAP S/4HANA Implementation project.

Q. Please explain the breakeven point for the Company's B/C Ratio (Overall).

A. Using the Company's internal BPS B/C Ratio (Overall), the breakeven point is equal to zero where financial benefits and total costs are equal. If the result of the calculation is greater than zero, financial benefits exceed costs. If the result is less than zero, total cost of ownership exceeds the financial benefit.

Q. Does the cost summary component in the Company's B/C Ratio (Overall) use the total one-time project cost, or the total one-time project cost plus the ongoing support costs?

A. The Company's internal BPS B/C Ratio (Overall) cost summary denominator uses total one-time project cost plus the ongoing support costs.

Q. Where is the total Company project cost number distinguished from the total Company project cost number that includes ongoing maintenance cost?

A. The total one-time Company project cost is the Total Project Cost at the bottom right corner of the Funding Summary Section of Exhibit A-22 (SHB-7) and Confidential Exhibit A-23 (SHB-8). This section of the Funding Summary section, starting with Labor, lists the breakdown of different cost categories for this investment. The total projected Company cost of ownership, including annual ongoing support costs, is the Total Cost of Ownership value on the right of the Funding Summary Section.

INVESTMENT IDENTIFICATION, PRIORITIZATION, APPROVAL, AND PROJECT PLANNING

Q. Please describe how technology projects are initiated, prioritized, and approved within the Company.

A. The initiation of a technology project begins with identification of a need for new or updated technology to meet the requirements of the Company's customers, including technology that customers interact with directly, and technology that sustains and improves reliability in service of customers. For example, IT collaborated closely with Company witnesses and representatives from the electric departments to identify technology projects and foundational digital investments necessary to enable the IRP and EDIIP. The joint

teams prepared business cases for each of the projects utilizing standard format and content.

After sponsor approval, individual projects are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects within the level of IT funding approved through the Company's budget and rate case process are selected for implementation and approved by each business area, followed by approval of the overall IT budget by the senior officer team. Due to the rapid pace of technology change and quickly changing business conditions, emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

Q. Please explain how IT's investment forecasts evolve over the course of project planning and implementation.

A. IT's investment forecasts begin with a ROM estimate. The Company uses the term "ROM" to characterize an initial estimate that includes research, analysis, and a business case. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to historical actual costs for similar projects. The purpose of the ROM estimate is to determine whether the estimated costs justify the value provided by the new capabilities without spending an inordinate amount of investment planning O&M developing the bottom-up estimate. From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery, the project team targets the delivery of the highest business value capabilities within the projected funding. In the case of traditional waterfall delivery, once

the formal design of a project has concluded, IT subject matter experts perform a detailed definitive estimate for execution. Factors may arise during project execution, such as resource needs, delays in receiving materials, changes in project schedule that shift spending between years, and changes in project scope or complexity that results in funding needs being lower or higher than initially estimated through the ROM process.

Q. Do the Company's total IT capital projections reflect a 20% reduction for those projects whose projections are based on a ROM?

A. Yes. Despite ROM cost-cutting concerns, the total capital projections include a 20% reduction for those projects whose projections are based on a ROM. In order to prevent over recovery, a 20% ROM adjustment is calculated by Business Category for those projects with a ROM estimate with the expectation that the full costs of approved projects may be recovered in a future rate case. These reductions are included in the table below and further reflected in Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6). Additionally, the ROM Adjusted Test Year Capital is identified for each project later in my testimony.

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2025	$37,036,237	$37,036,237
2026	$93,542,377	$82,391,259
2027	$89,189,423	$77,113,191
2028	$41,872,219	$38,950,039
Test Year	$66,301,973	$58,700,102

Q. Was this 20% reduction to capital expenditures for all ROM estimate projects a reaction to the Commission's decision on page 128 of its December 22, 2021 Order in Case No. U-20963?

A. Yes, in Case No. U-20963, Staff recommended a 20% disallowance for ROM estimates (Case No. U-20963, 6 TR 4081), and the Commission agreed saying that the ROM estimates are akin to contingency costs. The 20% reduction to capital expenditures for all ROM estimate projects used by IT in this case differentiates the Company's ROM estimates from the ROM estimates it used in Case No. U-20963 (in fact, the 20% reduction reflects Staff's position in Case No. U-20963) and further shows that the ROM estimate projects do not include contingency. Contingency is a project management best practice to add and reserve a percentage of a project's budget for unforeseen circumstances encountered during the course of the project. Due to previous disallowances, IT estimates do not include contingency. The ROM estimate is (1) intended to cover the full cost of the project rather than a portion, (2) built to address specific scope rather than unforeseen events, and (3) is calculated by technology and subject matter experts for a specific project whereas contingency is a percentage allocation based on an industry percentage value and/or project risk rating.

Q. Which exhibits contain the estimate breakdown for each project?

A. Exhibit A-20 (SHB-5) and Confidential Exhibit A-21 (SHB-6) contains each project's electric allocation spend for the applicable year or years broken down by software, materials, labor, contractor costs, non-labor overhead, and non-labor other costs. Exhibit A-22 (SHB-7) and Confidential Exhibit A-23 (SHB-8) contains Company spend for each project in the historical, bridge, and test years, broken down by year, that shows:

- Staffing;
- Outside Services;
- Business Expenses/Other;
- Employee Benefits;
- Materials, Licenses, Permit & Fees; and
- Other.

Q. Do all the projects included in the test year have project plans and schedules?

A. All projects included in the test year will have project plans and target dates at levels commensurate with their current phase. Some projects are continuing from an earlier period into the test year and have more definitive project plans for delivery. When the budget is released to a project to begin the official Plan phase, the product team will develop a more specific project plan that includes progressively more detail as the project moves through its different phases. In the case of projects executed using Agile methods, a high-level plan will be developed at the start of the project that includes an estimated number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will be delivered.

INVESTMENT PROJECTS

Q. Please provide a description of the various IT investment business categories or product lines to be highlighted in testimony.

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Exhibits A-20 (SHB-5), Confidential A-21 (SHB-6), A-22 (SHB-7), and Confidential A-23 (SHB-8). The IT investment projects are grouped into the following areas for explanation in testimony:

- **Electric and Electric & Gas Shared** projects that enable the IRP and EDIIP for Asset Management; Work Management; System Automation and Control, Security and Privacy; and Advanced Analytics that are necessary components to enable the Company to be an energy partner that customers, regulators, and the people of Michigan can count on to provide a safe, affordable, reliable, clean, and equitable electric system;

- **Customer** projects that are necessary to enable the Company to comply with regulatory billing changes, improve billing functionality, implement capabilities to assist low-income customers with energy assistance, increase the Company's ability to serve customers within the channel of their choice, and engage customers to enroll in demand response and energy waste reduction programs;

- **Corporate** projects that support internal departments of the Company are crucial to running an efficient business such as Treasury; Tax; Legal; HR, also known as People and Culture; Governmental, Regulatory and Public Affairs; Supply Chain and Facilities, also known as Operations Support; Finance; and Risk & Compliance;

- **IT/Digital Foundation** projects create the technology platforms, tools, processes, and frameworks that are required to enable IRP, EDIIP, and customer service outcomes. This includes ARP, application currency, upgrade and replacements, and digital and foundation capabilities projects; and

- **Security** projects are necessary to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat occurs, comply with all governmental and industry regulations, and enable the Company to secure customer data.

IT Projects Enabling Other Areas

Q. Please explain the Electric and Electric & Gas Shared projects enabling IRP and EDIIP.

A. Below are the projects enabling the IRP and EDIIP. Investments in digital capabilities are essential to achieving the Company's IRP and EDIIP business plans and Work Management improvements. A synopsis of each project with its value is included in the testimony of other Company witnesses, as indicated below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Witness	Exhibit References
Service Restoration Artificial Intelligence	$331,010	$264,808	$39,963	J. Dickey	A-12 (SHB-4), Schedule B-5.5, line 3 A-19 (SHB-3), line 1
Advanced Distribution Management System (ADMS) Software and Hardware Upgrade	$5,468,229	$4,374,583	269,791	J. Dickey	A-12 (SHB-4), Schedule B-5.5, line 3 A-19 (SHB-3), line 1
Integrated Energy Management Platform Optimization	$2,841,281	$2,273,025	$1,091,157	J. Dickey	A-12 (SHB-4), Schedule B-5.5, line 3 A-19 (SHB-3), line 1
Electric GIS Design Platform Modernization	$2,087,335	N/A	136,794	E. Duke	A-12 (SHB-4), Schedule B-5.5, line 3 A-19 (SHB-3), line 1
Electric GIS Utility Network Transformation	$6,065,639	$4,852,511	$1,538,783	J. Dickey	A-12 (SHB-4), Schedule B-5.5, line 3 A-19 (SHB-3), line 1

Additionally, the Application Currency-Electric-O&M, Application Currency-Electric & Gas Shared-O&M, Product Family Enhancements-Electric-O&M and Capital, and Product Family Enhancements-Electric & Gas Shared-O&M and Capital will be discussed later in my testimony.

Q. Are there any Electric projects with variances from the previous Case No. U-21870 that you would like to discuss?

A. Yes. The following Electric project is addressed below.

- Catastrophic Crewing (CatCrew) Version 2.0;

- Electric GIS Utility Network Transformation; and
- Ransomware Recovery-OT-Electric & Generation.

Q. What were the total projected capital expenditures for the Catastrophic Crewing (CatCrew) Version 2.0 in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the Catastrophic Crewing (CatCrew) Version 2.0 project are in the table provided below.

Catastrophic Crewing (CatCrew) Version 2.0			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 Reference**
2024 Actuals			
Software	$0	$0	A-20 (SHB-5), line 22, column m
Material	$0	$0	A-20 (SHB-5), line 22, column n
Labor	$177,863	$177,863	A-20 (SHB-5), line 22, column o
Contractor	$463,556	$463,556	A-20 (SHB-5), line 22, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 22, column q
Non-Labor Other	$53,750	$53,750	A-20 (SHB-5), line 22, column r
Total 2024 Projected	**$695,169**	**$695,169**	A-20 (SHB-5), line 22, column l
2025 Projected			
Software	$0	$0	A-20 (SHB-5), line 122, column m
Material	$0	$0	A-20 (SHB-5), line 122, column n
Labor	$728,000	$728,000	A-20 (SHB-5), line 122, column o
Contractor	$0	$0	A-20 (SHB-5), line 122, column p
Non-Labor Overhead	$50,960	$50,960	A-20 (SHB-5), line 122, column q
Non-Labor Other	$420,420	$420,420	A-20 (SHB-5), line 122, column r
Total 2025 Projected	**$1,199,380**	**$1,199,380**	A-20 (SHB-5), line 122, column l
2026 Projected			
Software	$0	$0	A-20 (SHB-5), line 199, column m
Material	$0	$0	A-20 (SHB-5), line 199, column n
Labor	$320,000	$320,000	A-20 (SHB-5), line 199, column o
Contractor	$0	$0	A-20 (SHB-5), line 199, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 199, column q

Non-Labor Other	$207,200	$207,200	A-20 (SHB-5), line 199, column r
Total 2026 Projected	**$527,200**	**$527,200**	A-20 (SHB-5), line 199, column l
Total Projected			
Software	$0	$0	
Material	$0	$0	
Labor	$1,225,863	$1,225,863	
Contractor	$463,556	$463,556	
Non-Labor Overhead	$50,960	$50,960	
Non-Labor Other	$681,370	$681,370	
Total Projected	**$2,421,749**	**$2,421,749**	

Q. What are the current projected total project costs broken down by year for the Catastrophic Crewing (CatCrew) Version 2.0 project?

A. The total project costs broken down by year for the Catastrophic Crewing (CatCrew) Version 2.0 project are in the table provided below.

Catastrophic Crewing (CatCrew) Version 2.0			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 / U-22070 Reference**
2024 Actuals			
Software	$0	$0	U-21870 A-20 (SHB-5), line 22, column m
Material	$0	$0	U-21870 A-20 (SHB-5), line 22, column n
Labor	$177,863	$177,863	U-21870 A-20 (SHB-5), line 22, column o
Contractor	$463,556	$463,556	U-21870 A-20 (SHB-5), line 22, column p
Non-Labor Overhead	$0	$0	U-21870 A-20 (SHB-5), line 22, column q
Non-Labor Other	$53,750	$53,750	U-21870 A-20 (SHB-5), line 22, column r
Total 2024 Actuals	**$695,169**	**$695,169**	U-21870 A-20 (SHB-5), line 22, column l
2025 Actuals			
Software	$0	$0	U-22070 A-20 (SHB-5), line 24, column m

Material	$0	$0	U-22070 A-20 (SHB-5), line 24, column n
Labor	$486,277	$486,277	U-22070 A-20 (SHB-5), line 24, column o
Contractor	$1,072,880	$1,072,880	U-22070 A-20 (SHB-5), line 24, column p
Non-Labor Overhead	$0	$0	U-22070 A-20 (SHB-5), line 24, column q
Non-Labor Other	$199,311	$199,311	U-22070 A-20 (SHB-5), line 24, column r
Total 2025 Actuals	**$1,758,467**	**$1,758,467**	U-22070 A-20 (SHB-5), line 24, column l
2026 Projected			
Software	$0	$0	U-22070 A-20 (SHB-5), line 117, column m
Material	$0	$0	U-22070 A-20 (SHB-5), line 117, column n
Labor	$230,187	$230,187	U-22070 A-20 (SHB-5), line 117, column o
Contractor	$542,093	$542,093	U-22070 A-20 (SHB-5), line 117, column p
Non-Labor Overhead	$0	$0	U-22070 A-20 (SHB-5), line 117, column q
Non-Labor Other	$106,559	$106,559	U-22070 A-20 (SHB-5), line 117, column r
Total 2026 Projected	**$878,838**	**$878,838**	U-22070 A-20 (SHB-5), line 117, column l
Total Projected			
Software	$0	$0	
Material	$0	$0	
Labor	$894,327	$894,327	
Contractor	$2,078,528	$2,078,528	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$359,620	$359,620	
Total Projected	**$3,332,475**	**$3,332,475**	

Q. Why have the projected costs of the Catastrophic Crewing (CatCrew) Version 2.0 project changed from previous projections in Case No. U-21870?

A. The projected capital costs for the Catastrophic Crewing (CatCrew) Version 2.0 project increased by $0.91 million in electric allocation relative to the projections presented in

Case No. U-21870. Higher contractor costs of $1.61 million primarily drove this increase. Reductions in internal labor of $0.33 million, non-labor overhead of $0.05 million, and non-labor other costs of $0.32 million partially offset those contractor costs.

In Case No. U-21870, the Company developed its estimates based on a defined scope focused on remediating identified security vulnerabilities and delivering core functionality identified at project initiation. During project execution, the Company determined that the existing CatCrew system presented operational limitations that constrained its ability to efficiently support evolving storm restoration requirements. Specifically, the system relied on a high degree of manual processing, provided limited real-time visibility into resources and storm activity, and offered reporting capabilities that did not fully support current operational needs.

To address these limitations, the Company expanded the project scope to deliver STAR Manager as a modernized, integrated replacement platform. During the design phase, the Company determined that upgrading SQL Server from Version 2016 to Version 2022 was appropriate to improve system performance, reliability, and scalability and to support anticipated future operational demands. The Company also implemented dedicated reporting database nodes to maintain production system performance while enabling enhanced reporting and analytics needed during storm events.

The Company also incorporated StormHub functionality directly into STAR Manager, which reduced system dependencies and improved data consistency, system reliability, and timeliness of information during storm operations. In addition, following Verizon's announcement of the retirement of the Company's existing text-messaging platform, the Company implemented integration with ARCOS to ensure continued, reliable

storm activation, and responder communications. This integration was necessary to maintain continuity of operations and effective coordination with field personnel.

End user tabletop exercises conducted during project execution identified additional requirements that enhanced operational effectiveness. These requirements focused on improving situational awareness of crew availability and deployment, streamlining activation and release processes, strengthening logistics coordination, enhancing reporting accuracy, and reducing manual intervention during storm response activities. These improvements support more efficient restoration efforts, improved utilization of resources, reduced operational risk, and improved customer outcomes.

Overall, the expanded scope establishes a foundation that supports improved crew productivity, faster customer restoration, reduced exposure to automated outage credits, and improved customer satisfaction during major storm events. This approach increased contractor costs by $1.61 million, which lower internal labor and non-labor costs partially offset, resulting in a net $0.91 million increase in projected capital costs.

Q. What were the total projected capital expenditures for the Electric GIS Utility Network Transformation project in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the Electric GIS Utility Network Transformation project are in the table provided below.

Electric GIS Utility Network Transformation			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 Reference**
2027 Projected			
Software	$1,800,000	$1,800,000	A-20 (SHB-5), line 277, column m
Material	$0	$0	A-20 (SHB-5), line 277, column n
Labor	$235,106	$235,106	A-20 (SHB-5), line 277, column o
Contractor	$1,702,591	$1,702,591	A-20 (SHB-5), line 277, column p

Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 277, column q
Non-Labor Other	$234,978	$234,978	A-20 (SHB-5), line 277, column r
Total 2027 Projected	**$3,972,675**	**$3,972,675**	A-20 (SHB-5), line 277, column l
2028 Projected			
Software	$45,000	$45,000	
Material	$0	$0	
Labor	$1,319,367	$1,319,367	
Contractor	$6,507,208	$6,507,208	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$1,560,855	$1,560,855	
Total 2028 Projected	**$9,432,430**	**$9,432,430**	
2029 Projected			
Software	$22,500	$22,500	
Material	$0	$0	
Labor	$894,973	$894,973	
Contractor	$4,045,908	$4,045,908	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$1,010,186	$1,010,186	
Total 2029 Projected	**$5,973,567**	**$5,973,567**	
Total Projected			
Software	$1,867,500	$1,867,500	
Material	$235,106	$235,106	
Labor	$3,916,931	$3,916,931	
Contractor	$10,553,116	$10,553,116	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$2,806,019	$2,806,019	
Total Projected	**$19,378,672**	**$19,378,672**	

Q. What are the current projected total project costs broken down by year for the Electric GIS Utility Network Transformation project?

A. The total project costs broken down by year for Electric GIS Utility Network Transformation project are in the table provided below.

Electric GIS Utility Network Transformation			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-22070 Reference**
2027 Projected			
Software	$1,800,000	$1,800,000	A-20 (SHB-5), line 193, column m
Material	$0	$0	A-20 (SHB-5), line 193, column n
Labor	$370,745	$370,745	A-20 (SHB-5), line 193, column o
Contractor	$1,702,591	$1,702,591	A-20 (SHB-5), line 193, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 193, column q
Non-Labor Other	$234,978	$234,978	A-20 (SHB-5), line 193, column r
Total 2027 Projected	**$4,108,314**	**$4,108,314**	A-20 (SHB-5), line 193, column l
2028 Projected			
Software	$45,000	$45,000	A-20 (SHB-5), line 263, column m
Material	$0	$0	A-20 (SHB-5), line 263, column n
Labor	$1,867,227	$1,867,227	A-20 (SHB-5), line 263, column o
Contractor	$6,507,208	$6,507,208	A-20 (SHB-5), line 263, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 263, column q
Non-Labor Other	$1,560,855	$1,560,855	A-20 (SHB-5), line 263, column r
Total 2028 Projected	**$9,980,290**	**$9,980,290**	A-20 (SHB-5), line 263, column l
2029 Projected			
Software	$22,500	$22,500	
Material	$0	$0	
Labor	$1,240,835	$1,240,835	
Contractor	$4,045,908	$4,045,908	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$1,010,186	$1,010,186	
Total 2029 Projected	**$6,319,429**	**$6,319,429**	
Total Projected			
Software	$1,867,500	$1,867,500	
Material	$0	$0	
Labor	$3,478,807	$3,478,807	
Contractor	$12,255,707	$12,255,707	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$2,806,019	$2,806,019	
Total Projected	$20,408,033	$20,408,033	

Q. Why have the projected costs of the Electric GIS Utility Network Transformation project changed from previous projections in Case No. U-21870?

A. The projected capital costs for the Electric GIS Utility Network Transformation project increased by $1.03 million in total Company and electric allocation compared to the projections provided in Case No. U-21870. This increase reflects higher contractor costs of $1.70 million, partially offset by decreases in material costs of $0.24 million and labor costs of $0.44 million.

The primary driver of the $1.03 million increase is expanded vendor development support required to implement the Utility Network solution, along with the associated IT administration cost allocations. Vendor expertise was always anticipated and included in the original estimates; however, the level of vendor involvement increased based on early lessons learned from execution of the Gas Utility Network effort. These early insights indicate that additional specialized vendor development support will be necessary to address implementation complexity and ensure a stable and scalable Utility Network solution.

Contractor costs increased due to the additional vendor development work that will be required to remediate and update existing GIS solutions impacted by the transition to the Utility Network data model. These remediation activities are necessary to align legacy solutions and integrations with the new Utility Network architecture.

Labor costs decreased as work originally planned for internal resources shifted to the vendor to leverage specialized Utility Network expertise. Material costs decreased due to scope adjustments informed by execution of the Gas Utility Network project, which reduced overall material requirements for the electric implementation.

Q. Why are there negative capital expenditures in 2026 for the Ransomware Recovery-OT-Electric & Generation project in Exhibit A-20 (SHB-5), line 114?

A. There are negative capital expenditures in 2026 in Exhibit A-20 (SHB-5), line 114, due to a prior period adjustment for hardware costs charged to this project in 2025, that were corrected in 2026 and charged to the correct project.

Q. Please explain the test year projects included in the Customer area.

A. Below are projects included within the Customer area. These digital investments support lower cost of customer service, increase customer engagement and enrollment in programs, and increase use of digital platforms. A synopsis of each project with its value is included in the direct testimony of Company witness Alex M. Gast:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M	Exhibit References
Energy Assistance Enhancements and Maintenance Annual Updates	$0	$0	$184,566	A-12 (SHB-4), Schedule B-5.5, line 2 A-19 (SHB-3), line 1

Additionally, the Application Currency-Customer-O&M and Product Family Enhancements-Customer-O&M and Capital will be discussed later in my testimony.

Q. Are there any Customer projects with disallowances from Case No. U-21870 that you would like to discuss?

A. Yes. The Web Chat AI enhancement that is a portion of the Product Family Enhancements-Customer-Capital project.

Q. Please briefly describe the Web Chat AI enhancement that is a portion of the Product Family Enhancements-Customer-Capital project.

A. Web Chat AI is a phased enhancement to the Company's website chatbot. The first phase was launched in January 2026 as a basic question and answer search tool. To date, it has handled over 24,000 customer conversations and is estimated to have reduced nearly 21,000 live contact-center calls. The Company plans in 2026 further releases for authenticated, account-specific support (balances and payments) and self-service high-bill analysis, with additional self-service features planned for 2027 (e.g., outage reporting and alerts). Refer to the direct testimony of Company witness Gast for further information on early indicators of success since the chatbot launched.

Q. What costs is the Company projecting for the Web Chat AI enhancement in this case?

A. The Company is projecting $61,825 in capital expenditures for the Bridge Period ending April 30, 2027, $123,650 in capital expenditures for the Test Year ending April 30, 2028, and $23,520 in O&M expenses for the Test Year ending April 30, 2028 for the Web Chat AI enhancement that is a part of the Product Family Enhancements-Customer-Capital project in this case.

Q. What is the current status of the Company's Website Redesign project?

A. The Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation. The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/SaaS version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has

extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule. In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign. It is important to note that improvements to the Company's website design, content, navigation, accessibility, and features are not static or stopped until the website redesign project is undertaken. The Company is regularly prioritizing and executing updates to web pages, content, and flows based on customer needs and challenges. An example of this is for the Low and Moderate Income ("LMI") Customer Support Enhancement. In fact, much of the investment in this enhancement is being achieved through updates to website design, content, features, and navigation, without the full re-architecture associated with the eventual website redesign project.

Q. Do you agree that the Company's website redesign would negate the need to make investments in Customer Self-Service Mobile Application and Web Chat AI?

A. No. The Website Redesign would not negate the need to make investments in the Customer Self-Service Mobile Application, Web Chat AI, or any other channels preferred by customers for specific needs, as discussed in Company witness Gast's testimony.

Q. Please explain the projects included in the Corporate area.

A. Below are projects included within the Corporate area. These digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the direct testimony of Company witness Matthew J. Foster:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Exhibit References
Enterprise Risk Management	$40,671	$32,537	$13,542	A-12 (SHB-4), Schedule B-5.5, line 1 A-19 (SHB-3), line 1

Additionally, the Application Currency-Corporate-O&M and Product Family Enhancements-Corporate-O&M and Capital will be discussed later in my testimony.

IT/Digital Foundations and Capabilities

ARP

Q. Please explain the value of projects included in ARP, and how the Company determines the hardware refresh frequency.

A. The Company's ARP projects replace technology assets in line with industry and Company life-cycle expectations for the specific assets in each type of program. Replaced assets are recycled, donated, or sold if there is residual value. The Company's research shows that industry standards on refreshing hardware are generally three to five years, although the Company refreshes monitors every eight years based on Company data related to historical failure rates. Refreshing hardware at the recommended cycle allows the Company to: (1) reduce security risks and help ensure devices are updated and patched to avoid vulnerabilities; (2) avoid costs due to increasing hardware failures; (3) avoid frustration for its customers and lost productivity for its employees due to downtime; (4) receive continued operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required hardware to support their work.

Below is a link to information on industry standards the Company has reviewed in determining its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle[5]

Q. Please describe Exhibit A-24 (SHB-9).

A. Exhibit A-24 (SHB-9) shows the detailed projected and actual capital expenditures of each ARP. Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides the total number of units for the specified year;
- Columns (e) through (f) provide total actual or projected capital expenditures for the specified year;
- Column (g) provides the total projected capital expenditures for the test year or the total actual electric allocation of capital expenditures for the specified year; and
- Column (h) provides electric allocation of capital expenditures for the specified year.

Q. Please explain the ARP and infrastructure projects, as reflected in Exhibit A-24 (SHB-9).

A. Each page of Exhibit A-24 (SHB-9) relates to a different ARP and infrastructure project, which I discuss further below.

Q. Please explain the ARP-Collaboration project.

A. The ARP-Collaboration project has the following synopsis:

- The **ARP-Collaboration** project requires $905,250 in capital and $113,818 in O&M in the test year.
  - **Description:** This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment.

[5] Sec-829-Report-of-PA-166---IT-Lifecycle-2023.pdf

- **Problem Statement:** 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.
- **Objectives:** 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.
- **Scope:** The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements.
- **Alternatives:** The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project differ from the $1,022,838 projected in Case No. U-21870?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of $694,358 (Exhibit A-20 (SHB-5), line 137, column (n)) is $328,480 less than the $1,022,838 projected in Case No. U-21870 (Exhibit A-20 (SHB-5), line 217, column (n)).

The following describes the primary reasons for the difference:

1. Reduction in average unit costs for the Conference Room refresh/modernization – Auditorium Refreshes in 2026 of $0.02 million.
2. Removal of two Conference room refresh/modernize – Medium for 2026 that were inadvertently included in the previous case of $0.02 million.
3. Reduction in the average unit costs for the Conference Room refresh/modernization – Large of $0.03 million due to the Company identifying

streamlined technology, which eliminates the dedicated video conferencing systems and large equipment cabinets.

4. Removal of Surface Hubs 50" and Surface Hubs 85" from 2026 of $0.27 million, due to Microsoft advising the Company that the hubs would cease functioning because Windows 10 had reached end of life. The Company had initially planned to operate the devices without support. Based on Windows 10 reaching end of life and the devices no longer functioning, the Company determined the need to upgrade the Surface Hubs 50" in 2025 to maintain compliance with security and support standards. The Surface Hubs 50" and Surface Hubs 85" refreshes are no longer required in 2026.

5. Increase of accessories of $0.05 million required for the implementation of collaboration assets.

Q. Please explain the change made with the ARP-Cyber Security project.

A. Beginning in 2025, the ARP-Cyber Security project was replaced with ARP-Cyber Security-Common, ARP-Cyber Security-Electric, and ARP-Cyber Security-Gas projects to improve the tracking of these assets and better align the projects with the resources performing the work.

Q. Did the Company incur any capital expenditures or O&M expense for the ARP-Cyber Security project in 2025?

A. The Company incurred capital expenditures and O&M expenses for the ARP-Cyber Security project in 2025 for materials that were purchased in 2024 and implementation was completed in 2025. The Company made the decision to complete the work under the original project to minimize administrative burden. The table below provides the cost category breakdown of the actual 2025 electric allocation capital expenditures and O&M expenses.

ARP-Cyber Security		
Electric Allocation		
	2025 Actuals	
Cost Category	**Capital**	**O&M**
Software	$0	$0
Material	($1,052)	$0
Labor	$51,023	$4,267
Contractor	$13,734	$722
Non-Labor Overhead	$0	$0
Non-Labor Other	$13,111	$0
Total 2025 Actuals	**$76,816**	**$4,989**

Q. Please explain the ARP-Cyber-Common project.

A. The ARP-Cyber-Common project has the following synopsis:

- The **ARP-Cyber-Common** project requires $638,243 in capital and $9,546 in O&M in the test year.
  - **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.
  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.
  - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.
  - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades.
  - **Alternatives:** The alternatives considered include: (1) upgrade or replace only the assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle.

This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.

Q. Please explain the ARP-Cyber-Electric project.

A. The ARP-Cyber-Electric project has the following synopsis:

- The **ARP-Cyber-Electric** project requires $438,018 in capital and $18,013 in O&M in the test year.
  - **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.
  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.
  - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.
  - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades.
  - **Alternatives:** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.

Q. Please explain the ARP-FDAM project.

A. The ARP-FDAM project has the following synopsis:

- The **ARP-FDAM** project requires $3,496,151 in capital and $2,240 in O&M in the test year.

- **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.
- **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:** 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.

Q. Does the Company agree with the Commission and Staff, as stated in other cases, that using a more explicit or specific method for projecting new purchases for the ARP-FDAM and ARP-WAM projects would provide more certainty in the projected costs?

A. Yes. The Company agrees that using a four-year historical average for new field devices and workstations purchases and providing information about any adjustments would be a more explicit or specific method to calculate the total projected costs for new field device purchases for the ARP-FDAM project. I have provided information in Exhibit A-25

(SHB-10), that will permit this approach for this case, and the Company commits to using this method in future cases as well.

Q. Did the Commission find that the more explicit or specific method used in Case No. U-21870 to calculate the total projected costs for new field device purchases for the ARP-FDAM project sufficiently supported the need for these expenditures?

A. Yes. In the Commission's March 27, 2026 Order in Case No. U-21870, page 186, the Commission agreed that the Company sufficiently supported the need for the new field purchases for the ARP-FDAM project and adequately explained its revised projections, which were based on a four-year historical average as in this case.

Q. Please describe Exhibit A-25 (SHB-10).

A. Exhibit A-25 (SHB-10) is the four years of historical actuals data for the Years 2022, 2023, 2024, 2025 and total Company and electric allocation four-year historical average calculations for the costs associated with new purchases of field devices and workstations for the ARP-FDAM and ARP-WAM projects. Specifically:

- Column (a) provides each historical year used in the total Company and electric allocation four-year historical average calculations;
- Column (b) provides the actual data for each historical year and the total Company and electric allocation four-year historical average calculations; and
- Column (c) provides a reference to the exhibits from prior cases where historical actual data was provided.

Q. How are the annual projected capital expenditures created for the ARP-FDAM project?

A. The ARP-FDAM project has two categories, which are replacements and new purchases. Each of these categories include field devices. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - Field devices scheduled retirement year is four years from purchase;
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for field devices are projected based on the number of planned replacements and include desk docks, vehicle docks, and ac adapters; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are projected at $0.69 million annually for 2027 and 2028.
    - The Company calculated the four-year historical average for the ARP-FDAM new purchases based on the actual costs provided in Exhibit A-25 (SHB-10), page 1, line 5; and
  - The costs cover the field devices required for the employee/contractor and associated accessories.

The four-year cycle for field devices, along with the projected new purchases, are listed in the associated Exhibit A-24 (SHB-9).

Q. How are the annual projected O&M expenses projected for the ARP-FDAM project?

A. The annual projected O&M expenses for the ARP-FDAM project are based on the average of four years of historical actuals data provided in the table below.

Year	Total Company O&M
2022	$9,063
2023	$2,491
2024	$2,752
2025	$(82)
Four Year Historical Average	$3,556

Q. Please describe variances from year to year for the ARP-FDAM project.

A. Variances for the ARP-FDAM project are a result of changes to new purchases, scheduled replacements, and incremental unit costs. Starting in 2024, there has been a one-time change for new field device purchases. These devices are now a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. These devices were included in ARP-FDAM starting in the year 2024 going forward. Exhibit A-24 (SHB-9), page 4, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	Field Device	Reason for variance
2025 Actual	532	• Field device replacements based on refresh schedules.
2026 Plan	1,338	• Field device replacements based on refresh schedule. • 215 field device replacements moved from ARP-WAM to ARP-FDAM. • 425 field device replacements that were purchased as a part of other efforts in 2022.
2027 Plan	972	Field device replacements based on refresh schedule.
2028 Plan	828	Field device replacements based on refresh schedule.

New Purchases

Year	Field Device	Reason for variance
2025 Actual	90	Field devices based on actual new employee/contractors.
2026 Plan	N/A	Three-Year Historical Average - $0.89 million

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project differ from the $2,172,954 projected in Case No. U-21870?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project of $1,623,447 (Exhibit A-20 (SHB-5), line 54, column (n)) are $549,507 less than the $2,172,954 projected in Case No. U-21870 (Exhibit A-20 (SHB-5), line 144, column (n)).

The following describes the reason for the difference:

1. Field device replacements decreased by $0.14 million, attributable to the following:

   - Decrease of $0.12 million due to reduction in unit cost from $4,883 to $3,860, partially offset by 24 more units being replaced with CF33 field device model;

   - Decrease of $0.07 million due to reduction in unit cost from $4,004 to $3,166, partially offset by 28 more units being replaced with CF55 field device models than planned; and

   - Increase of $0.05 million due to accessories for field devices that were not previously projected.

Q. Please explain the changes made with the ARP-Core Network, ARP-LAN, and ARP-Infoblox projects.

A. Beginning in 2025, the ARP-Core Network, ARP-LAN, and ARP-Infoblox Refresh projects have been replaced with ARP-Network-Common, ARP-Network-Electric, and ARP-Network-Gas projects due to the move of network resources to Security. In addition, a portion of the units from the ARP-OT Electric have been moved to these new projects. These changes were made to improve tracking of these assets and better align the projects with the resources performing the work.

Q. Did the Company incur any capital expenditures or O&M expenses for the ARP-Infoblox Refresh project in 2025?

A. The Company incurred electric allocation capital expenditures of $203,605 and O&M expenses of $4,507 for the ARP-Infoblox Refresh project in 2025. In September 2025, the Company made the decision to transition from the Infoblox to TCPWave solution. Infoblox increased prices and switched to a subscription licensing model, making the existing Infoblox solution cost prohibitive. TCPWave delivers equivalent functionality at a lower total cost of ownership. The Company inadvertently recorded actuals in 2025 for the TCPWave solution that replaced Infoblox in the ARP-Infoblox Refresh project in gas Case No. U-21981. The units are provided in Exhibit A-24 (SHB-9), page 5. In the future, the Company will no longer use the ARP-Infoblox project.

Q. Please explain the ARP-Network-Common project.

A. The ARP-Network-Common project has the following synopsis:

- The **ARP-Network-Common** project requires $668,347 in capital and $13,332 in O&M in the test year.
  - **Description:** This project will refresh data center network equipment, LAN, wireless local area network ("WLAN"), and equipment to efficiently manage and control the Company's networks shared by Electric and Gas.
  - **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 hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

Q. Please explain the ARP-Network-Electric project.

A. The ARP-Network-Electric project has the following synopsis:

- The **ARP-Network-Electric** project requires $50,143 in capital and $1,018 in O&M in the test year.
  - **Description:** This project will refresh data center network equipment, LAN, WLAN, and equipment to efficiently manage and control the Company
  - **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) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor

support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

Q. Please explain the ARP-OT Support Common project.

A. The ARP-OT Support Common project has the following synopsis:

- The **ARP-OT Support Common** project requires $1,224,095 in capital and $115,389 in O&M in the test year.
    - **Description:** The ARP-OT Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating 5-year refresh schedule.
    - **Problem Statement:** When OT 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.

Q. Please explain the ARP-OT Support Electric project.

A. The ARP-OT Support Electric project has the following synopsis:

- The **ARP-OT Support Electric** project requires $1,320,625 in capital and $201,223 in O&M in the test year.
    - **Description:** The ARP-OT Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule.
    - **Problem Statement:** When OT assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.
    - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure.
    - **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.
    - **Alternatives:** The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.

Q. Please explain the ARP-Physical Security project.

A. The ARP-Physical Security project has the following synopsis:

- The **ARP-Physical Security** project requires $1,400,526 in capital and $7,954 in O&M in the test year.
    - **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.

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

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

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

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

Q. Please explain the ARP-Printer Asset Management ("PAM") project.

A. The ARP-PAM project has the following synopsis:

- The **ARP-PAM** project requires $349,790 in capital and $5,326 in O&M in the test year.

  - **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.

- **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.

Q. How are the annual projected O&M expenses projected for the ARP-PAM project?

A. The annual projected O&M expenses for the ARP-PAM project are based on the average of four years of historical actuals data provided in the table below.

Year	Total Company O&M
2022	$11,431
2023	$19,064
2024	$0
2025	$3,322
Four Year Historical Average	$8,454

Q. Please explain the ARP-Radio project.

A. The ARP-Radio project has the following synopsis:

- The **ARP-Radio** project requires $910,117 in capital and $56,855 in O&M in the test year.
    - **Description:** This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.
    - **Problem Statement:** 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers' service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.
    - **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.
    - **Scope:** The project scope consists of: (1) scheduled replacement of radios, modems, consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters and systems.
    - **Alternatives:** The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1

was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

Q. Please explain the ARP-Server and Storage project.

A. The ARP-Server and Storage project has the following synopsis:

- The **ARP-Server and Storage** project requires $259,430 in capital and $2,940 in O&M in the test year.
  - **Description:** This project will replace or augment server and storage infrastructure for the Company.
  - **Problem Statement:** When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five- to seven-year refresh cycle.
  - **Objectives:** This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.
  - **Scope:** The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.
  - **Alternatives:** The alternatives considered were to: (1) purchase extended maintenance; (2) move some of these assets to the cloud with the Digital - Hybrid Cloud and Data Center Migration project; or (3) replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.

Q. Do the Company's 2027 projected electric allocation capital expenditures for material costs for the ARP-Server and Storage project differ from the $752,127 projected in Case No. U-21870?

A. Yes. There are no 2027 projected electric allocation capital expenditures for material costs for the ARP-Server and Storage project. The Digital-Hybrid Cloud and Data Center Migration project moved enough of the Company's compute to the cloud sooner than anticipated, which allowed the Company to retire end-of-life assets without purchasing replacements, freeing up excess capacity as migrations progressed.

Q. Please explain the ARP-WAM project.

A. The ARP-WAM project has the following synopsis:

- The **ARP-WAM** project requires $5,537,843 in capital and $63,858 in O&M in the test year.
  - **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.
  - **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.

Q. Would increasing the replacement cycle for the ARP-WAM refresh cycle from four years to five to seven years have a negative impact on the Company and its customers?

A. Yes. Increasing the replacement cycle for Personal Computer ("PC") Devices from four years to five to seven years would have a negative impact on the Company and its customers. This is demonstrated through industry data, internal incident data, PC warranty duration, and lost productivity. These references reinforce replacing PCs at four years or less:

- Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
- https://i.crn.com/sites/default/files/ckfinderimages/userfiles/images/crn/custom/INTELBCCSITENEW/WhitePaper_EnterpriseRefresh.pdf

- The vendor's three-year warranty duration for Company PCs combined with the incident history reinforce four years is the optimum time for replacement.

The labor cost of addressing incidents and lost productivity, the warranty period, and external references confirm PC and field device replacement on a four-year cycle. Similarly, Company historical failure rates for monitors indicate an eight-year cycle as ideal, which is what the Company employs for monitors.

Q. How are the annual projected capital expenditures created for the ARP-WAM project?

A. The ARP-WAM project has two categories, which are replacements and new purchases. Each of these categories include PC devices and monitors. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - PC devices scheduled retirement year is four years from purchase, and
    - Monitors scheduled retirement year is eight years from purchase.
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for PC devices are projected based on the number of planned replacements and include keyboards, surge protectors, docks, backpacks, and cables; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are projected at $1.08 million annually for 2027 and 2028.
    - The Company calculated the four-year historical average for the ARP-WAM new purchases of $1.08 million based on the actual costs provided in Exhibit A-25 (SHB-10), page 2, line 5.
    - The costs cover the PC devices required for the employee/contractor and associated accessories.

The four-year cycle for PC devices and the eight-year cycle for monitors, along with the projected new purchases, are listed in the associated Exhibit A-24 (SHB-9).

Q. How are the annual projected O&M expenses projected for the ARP-WAM project?

A. The annual projected O&M expenses for the ARP-WAM project are based on the average of four years of historical actuals data provided in the table below.

Year	Total Company O&M
2022	$160,319
2023	$119,140
2024	$28,216
2025	$97,772
Four Year Historical Average	$101,362

Q. Please describe variances from year-to-year for the ARP-WAM project.

A. Variances for the ARP-WAM project are a result of changes to new purchases, scheduled replacements per four-year PC device and eight-year monitor refresh cycles, previous year deferrals for equipment replacements primarily due to disallowances, and incremental unit costs. Starting in 2024, there has been a one-time change for new field device purchases. These devices will now be a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. Exhibit A-24 (SHB-9), page 14, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	PC Device	Monitor	Reason for variance
2025 Actual	2,804	404	• 50 fewer PC devices for J. C. Campbell location that were no longer going to be replaced. • 35 Rack Mount device replacements deferred to 2026. • 79 fewer PC devices that are not planned to be replaced due to reduction in resources. • Monitor replacements included in 2025 are for monitors that have reached their eight-year replacement.
2026 Plan	1,885	0	• 297 fewer PC devices that are not planned to be replaced due to reduction in resources. • 35 reduced to 14 Rack mount replacements deferred from 2025. • No monitor replacements planned since most monitors' eight-year replacement cycle was completed from 2018-2021. The next major monitor replacement is targeted to resume in 2027.
2027 Plan	2,159	4,318	• Monitor replacements based on an eight-year replacement cycle.
2028 Plan	3,100	6,200	• Monitor replacements based on an eight-year replacement cycle.

New Purchases

Year	PC Device	Monitor	Reason for variance
2025 Actual	592	892	Based on actual new employee/contractor volume.
2026 Plan	N/A	N/A	Three-Year Historical Average of $1.0 million, adjusted

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $5,646,692 projected in Case No. U-21870?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project of $5,252,176 (Exhibit A-20 (SHB-5), column (n), line 59) are

$394,516 less than the $5,646,692 projected in Case No. U-21870 (Exhibit A-20 (SHB-5), column (n), line 148).

The following describes the difference:

1. Laptop and tablet replacements decreased by $0.82 million attributed to the removal of replacements planned for the J.H. Campbell Plant and fewer devices being replaced due to reductions in resources;

2. Rack mount device replacements decreased by $0.20 million due to the deferral of devices to 2026;

3. Accessories for replacements increased by $0.11 million;

4. Monitor replacement increased by $0.08 million; and

5. New Purchases increased by $0.44 million based on actual new employee/ contractor volume.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $4,013,510 projected in Case No. U-21870?

A. Yes. The Company's 2026 projected electric allocation capital expenditure for material costs for the ARP-WAM project of $3,486,135 (Exhibit A-20 (SHB-5), column (n), line 142) are $527,375 less than the $4,013,510 projected in Case No. U-21870 (Exhibit A-20 (SHB-5), column (n), line 221).

The following describes the difference:

1. Replacements decreased by $0.528 million based on current electric allocation factors that are updated annually offset by net of reduction 297 PC devices planned to be replaced and deferral of 14 Rack Mount devices from 2025; and

2. Accessories for replacements increased by $0.001 million; and

3. No change in new purchases.

Upgrades, Replacements, and Application Currency Projects

Q. What are Upgrades, Replacements, and Application Currency projects?

A. Upgrades, Replacements, and Application Currency projects are projects that address the need to upgrade or replace software applications and underlying platforms to a more current version to maintain prudent levels of security, reliability, and interoperability with associated systems. The Company performs security risk and various types of technical analysis to determine which applications need upgrading or replacing and when. Upgrade and replacement projects are created for larger and more complex application and platform upgrades or replacements that require increased oversight and project management. Smaller upgrades are aggregated by IT product line and spend type in the Application Currency projects.

Q. Please explain the Upgrades and Replacements projects.

A. The following is an explanation of the Upgrades and Replacements projects:

- The **Asset Accounting Tax Upgrade** project requires $156,074 in O&M in the test year.
    - **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.
    - **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.

- The **Asset Accounting Upgrade 2027-2028** project requires $267,127 in O&M in the test year.

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

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

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

(4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

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

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

- The **AxWay Secure Transport 2027 Upgrade** project requires $168,080 in O&M in the test year.

  - **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.

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

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

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

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

- The **Enterprise Service Bus ("ESB") 2026-2027 Upgrade** project requires $587,823 in capital ($470,258 ROM Adjusted Capital) and $424,830 in O&M in the test year.

  - **Description:** This project will upgrade the current ESB software versions in use at the company. This will also implement a container management system, which deploys, manages, and scales microservices or applications that send or receive data via the service bus, and migrate various services to containers.

  - **Problem Statement:** Newer ESB software versions offer improved integration with Rest/Application Programming Interface ("API") services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. The lack of a container management

solution prohibits the adoption of a more cloud native approach leading to retaining legacy solutions.

- **Objectives:** The value this project provides the Company includes: (1) implement a container management solution; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.
- **Scope:** The project scope includes (1) implementing the current version of all applications that are part of the ESB application, database version, and required database drivers and (2) implementing a Kubernetes solution for container management and migrate targeted services that are identified as microservices to containers.
- **Alternatives:** Alternatives considered included: (1) Accept the current version levels and continue to pay for extended support costs and accept technical obsolescence risk. (2) Only upgrade the existing applications. (3) Upgrade all of the applications as well as evolve the cloud-based instance to a more cloud native architecture by converting containers and implementing a Kubernetes solution to manage the containers. This option was selected because it best meets the Company needs for the near future by maintaining vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

- The **ESB 2028-2029 Upgrade** project $7,203 in O&M in the test year.
  - **Description:** This project will upgrade the current Enterprise Service Bus software versions in use at the Company.
  - **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) avoid extensive payments for extended 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.

- The **HR Support Pack and Business Software Inc. ("BSI") Upgrade 2027 and 2028** projects require the following O&M in the test year.

Project Year	Test Year O&M
2027	$279,355
2028	$139,678

  - **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.

  - **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 alternatives considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

- The **High Voltage Distribution ("HVD") SCADA Upgrade 2028-2029** project requires $593,623 in capital ($474,899 ROM Adjusted Capital) and $56,833 in O&M in the test year.
    - **Description:** The Electric HVD Monitoring System Upgrade project upgrades the software (every two years) and hardware components (every four years) of HVD SCADA system. This will include the upgrade of the underlying operating systems and database platforms that the software resides on as needed to maintain vendor support. This system is used to monitor and control generation and high voltage distribution voltage circuits. This project will add additional features and enhancements to HVD Monarch, the Company's HVD SCADA platform that improves efficiency and reliability.
    - **Problem Statement:** Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution ("LVD") system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities.
    - **Objectives:** Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems.
    - **Scope:** The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying operating systems and database platforms; (3) upgrading the underlying application hardware; (4) implementing new functionality for improved value to the Company; (5) making necessary configuration changes; and (6) updating documentation related to the integration changes.
    - **Alternatives:** Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two

versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) Move to cloud. This option was not chosen as CE's internal security requirement is to host control systems on premise. (5) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.

- The **ISIS Papyrus 2028 Upgrade** project requires $45,622 in O&M in the test year.
    - **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.
    - **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 as 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:** As this is an upgrade of an existing system, the alternative considered was to 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.

- The **Itron Enterprise Edition** ("IEE") **2027 Upgrade** project requires $111,642 in O&M in the test year.
  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.
  - **Problem Statement:** 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. 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; and (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 IEE applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.
  - **Alternatives:** Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's MDM) from the Itron security infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the initial multi-million dollar project. (3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **Rate Change Maintenance** project requires $188,272 in O&M in the test year.

- **Description:** The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.
- **Problem Statement:** For the Company to continue to meet and comply with the 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 MPSC; 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.

- The **SAP Support Pack Upgrade 2028** project requires $95,418 in O&M in the test year.
  - **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.
  - **Problem Statement:** To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches,

including security patches, and maintain application interoperability and stability.

- **Objectives:** The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

- **Scope:** The scope of this project includes routine support pack upgrades to all SAP applications, which include: Customer Relationship Manager ("CRM"), Enterprise Portal, Process Orchestration ("PO"), Business Warehouse ("BW"), Business Objects ("BOBJ"), Data Services ("DS"), Governance, Solution Manager, Data Quality Manager ("DQM"), System Landscape Directory ("SLD") and other related SAP applications.

- **Alternatives:** Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Secondary Upgrade 2027** project requires $44,421 in O&M in the test year.

  - **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.

  - **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 upgrading the Sitecore content management software to the latest available version.
- **Alternatives:** Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the need to prevent the application from falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrating to a cloud solution was also considered. This alternative was not chosen due to the cost/benefit analysis of re-architecting the Company's current Sitecore implementation to facilitate cloud migration that is not viable at this time; and (3) Rejecting these alternatives, the Company chose to upgrade Sitecore on a two-year cycle because it provides up to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

Q. Please describe Confidential Exhibit A-26 (SHB-11).

A. Confidential Exhibit A-26 (SHB-11) is a confidential exhibit that provides Application Currency Program projected capital and O&M spend and scope for each of the Application Currency projects. Specifically:

- Column (a) provides the application name;
- Column (b) provides a disaster recovery tier, where applicable;
- Column (c) provides total projected 2027 capital expenditures;
- Column (d) provides total projected 2027 O&M expense;
- Column (e) provides total projected 2028 capital expenditures;
- Column (f) provides total projected 2028 O&M expense;
- Column (g) provides total test year capital expenditures;
- Column (h) provides total test year O&M expense;

- Column (i) provides the electric allocation for test year capital expenditures; and
- Column (j) provides the electric allocation for test year O&M expense.

Application Currency information can be used to exploit known security vulnerabilities; therefore, the exhibit is confidential. Application names have been redacted to mitigate the risk of exploitation of known security vulnerabilities.

Q. How does the Company decide which applications to include in the Application Currency Program for the test year?

A. The Application Currency Program focuses on upgrades that maintain security and reliability of the application and underlying platforms, as well as maintaining vendor supported software versions. Not every application requires an upgrade each year, so the application data provided in Confidential Exhibit A-26 (SHB-11) is not inclusive of all applications that are in upgrade cycles beyond the test year. The Company considers the following when determining the next upgrade version:

- Compatibility with the current environment and underlying platforms;
- Compatibility with associated or integrated applications;
- Future planned changes that could sub-optimize the application;
- Cyber security drivers and requirements;
- Additional functionality offered with the new version; and
- Availability of the appropriate version.

The applications meeting the criteria for upgrade are then added to the application currency list, cross-checked against other current or future projects that may impact the upgrade, and then scheduled.

Q. Please explain the Application Currency projects.

A. The following describes the Application Currency projects:

- The **Application Currency - Capital** and **Application Currency - O&M:**
  - **Description:** These initiatives will utilize capital and O&M funding to keep applications current for security and reliability. O&M is included with capital projects to complete expense activities associated with capital upgrades.
  - **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 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 scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes.
  - **Alternatives:** Applications 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.

Specific spending requirements for each Application Currency project are indicated in the table below and supported with additional detail in Confidential Exhibit A-26 (SHB-11).

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Projected Test Year O&M
Application Currency-Corporate-O&M	$0	$0	$117,236
Application Currency-Customer-O&M	$0	$0	$12,006
Application Currency-Electric & Gas Shared-O&M	$0	$0	$381,275
Application Currency-Electric-O&M	$0	$0	$204,538
Application Currency-IT/Digital Foundation-Application Platforms-O&M	$0	$0	$187,381
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	$0	$0	$24,312
Application Currency-OT-O&M	$0	$0	$124,893
Application Currency-Security-Capital	$67,653	$0	$4,494
Application Currency-Security-O&M	$0	$0	$253,970

Q. Are there any differences between the previous electric rate case, Case No. U-21870, and this case related to the Application Currency O&M projects that you would like to discuss?

A. Yes. The O&M allocation for Application Currency O&M projects has been changed in this case. The projected O&M allocation factor allocates a portion of IT O&M costs to the business function it supports. The O&M allocation factor is updated annually and is based

on annual labor studies that are performed by each business function. The projected O&M allocation factor in each case is based on the current O&M allocation factor at that time. In the previous electric rate case, Case No. U-21870, the projected 2027 O&M allocation factor was 49.65736% and, in this case, the projected 2027 O&M allocation factor is 53.43%. This explains the small variances for individual application currency line items when comparing the Total 2027 O&M in U-21870, Exhibit A-23 (SHB-8), column f, to the Total 2027 O&M in Exhibit A-26 (SHB-11), column d, for this case.

Q. Are there any differences between the current gas rate case, Case No. U-21981, and this case related to the Application Currency O&M projects that you would like to discuss?

A. Yes. The total O&M projected costs in current gas rate case, Case No. U-21981, Exhibit A-26 (SHB-11), columns d and f, inadvertently did not have the projected O&M allocation applied. The projected total O&M costs should have reflected an O&M allocation factor of 53.43%. The Total Test Year O&M and gas allocation O&M amounts are correct, as the O&M allocation factor was applied when calculating these amounts.

Enhancement Projects

Q. What is the purpose of Enhancements investments?

A. Enhancements are smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions. Enhancement requests typically emerge from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other improvement ideas. Enhancements benefit customers and the Company through cost savings, cost avoidance, productivity improvements, safety

improvements, efficiencies, mandated regulatory changes, and improved customer experience.

Q. How does the Company track and manage enhancements?

A. The Company actively maintains a backlog of enhancements in Azure DevOps ("ADO"). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled.

Q. Please describe Exhibit A-27 (SHB-12).

A. Exhibit A-27 (SHB-12) is the Projected Test Year Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis and provides a summary of electric allocation enhancement projected test year and actual spend for the years 2023 through 2025. Specifically:

- Column (a) provides the enhancement project;
- Column (b) provides the total Company 2023 actual capital expenditure amounts;
- Column (c) provides the total Company 2024 actual capital expenditure amounts;
- Column (d) provides the total Company 2025 actual capital expenditure amounts;
- Column (e) provides the total Company three-year historical average capital expenditures based on 2023, 2024, and 2025;
- Column (f) provides the electric allocation 2027 projected capital expenditure amounts;
- Column (g) provides the electric allocation 2028 projected capital expenditure amounts;

- Column (h) provides the electric allocation projected Test Year capital expenditure amounts;
- Column (i) provides the total Company 2023 actual O&M expense amounts;
- Column (j) provides the total Company 2024 actual O&M expense amounts;
- Column (k) provides the total Company 2025 actual O&M expense amounts;
- Column (l) provides the total Company three-year historical average O&M expense based on 2023, 2024, and 2025;
- Column (m) provides the electric allocation 2027 projected O&M expense amounts;
- Column (n) provides the electric allocation 2028 projected O&M expense amounts; and
- Column (o) provides the electric allocation projected Test Year O&M expense amounts.

Q. Is the Company still using the total cumulative demand method to validate enhancement demand expenditures and expenses in the test year that it has used in prior cases?

A. No. The Company has discontinued the use of the total cumulative demand method for validating enhancement expenditures and expenses in the test year. By streamlining validation processes, the Company eliminates redundant work and focuses on methods that provide the most meaningful assurance of cost reasonableness.

Specifically, the Company has not observed a decline in demand for enhancements, as technology adoption continues to grow. This consistent or growing demand indicates that the risk of underestimating enhancement needs is low. Maintaining multiple validation methods, such as the total cumulative demand approach alongside the three-year historical average, would not yield additional value but would instead introduce unnecessary complexity and administrative burden.

By relying on the three-year historical average, the Company ensures that projections are grounded in actual spending patterns, which have proven to be stable and reflective of ongoing business needs.

Q. What method is the Company using to project the enhancement capital expenditures and O&M expenses in the test year?

A. The Company is using a three-year historical average method to project enhancement demand capital expenditures and O&M expenses in the test year. The Company calculated the actual capital and O&M total Company three-year historical average for 2023-2025 of $7,443,491 capital and $3,368,718 O&M expenses (Exhibit A-27 (SHB-12), line 49, columns (e) and (l)). The Company used this three-year historical average to project the projected electric allocation Test Year enhancement capital expenditures and O&M expenses of $5,173,419 capital and $1,952,337 O&M expenses (Exhibit A-27 (SHB-12), line 49, columns (h) and (o)).

Q. Did the Company project any additional known enhancement costs in this case?

A. Yes. In the Product Family Enhancements-Customer-Capital project, the Company included additional known enhancement costs for the Web Chat AI enhancement. This enhancement was discussed in detail previously in my direct testimony.

Q. Please explain the Enhancements projects.

A. The following are the Enhancements projects:

- The **Enhancements - Capital** and **Enhancements - O&M** requires the capital and O&M in the test year as described in the table below.
    - **Description:** These projects will utilize capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included with capital projects to complete expense activities associated with capital enhancements.

- **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 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 the respective business areas.

- **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 new functionality for business areas represented by each program.

- **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.

Specific spending requirements for each Enhancement project are indicated in the table below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
Enhancements-Security-Capital	$574,991	$0	$52,165
Enhancements-Security-O&M	$0	$0	$318,683
Product Family Enhancements-Application Platforms Services-Capital	$206,109	$0	$19,272
Product Family Enhancements-Application Platforms Services-O&M	$0	$0	$98,829
Product Family Enhancements-Corporate-Capital	$683,519	$0	$46,750
Product Family Enhancements-Corporate-O&M	$0	$0	$222,511
Product Family Enhancements-Customer-Capital	$ 1,636,450	$0	$ 366,355
Product Family Enhancements-Customer-O&M	$0	$0	$147,840
Product Family Enhancements-Electric & Gas Shared-Capital	$1,209,742	$0	$193,878
Product Family Enhancements-Electric & Gas Shared-O&M	$0	$0	$356,601
Product Family Enhancements-Electric-Capital	$719,345	$0	$188,564
Product Family Enhancements-Electric-O&M	$0	$0	$120,493
Product Family Enhancements-Infrastructure Platforms Services-Capital	$266,906	$0	$81,922
Product Family Enhancements-Infrastructure Platforms Services-O&M	$0	$0	$46,295

Digital Foundations and Capabilities Projects

Q. Please explain the Digital Foundations and Capabilities projects.

A. Below are the Digital Foundations and Capabilities projects:

- The **Data & Analytics Platform Rationalization** project requires $1,458,496 in capital and $247,145 in O&M in the test year.
  - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into the Data Lake in the cloud, and building visualizations from the data in the Data Lake.
  - **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.

Q. Please explain the Digital-Hybrid Cloud and Data Center Migration project.

A. The Digital-Hybrid Cloud and Data Center Migration project requires no capital expenditures and O&M expense in the test year and has the following synopsis:

- **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.

- **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.

Q. What were the total projected capital expenditures for the Digital-Hybrid Cloud and Data Center Migration in Case No. U-21870?

A. The Case No. U-21870 projected capital and O&M expenditures by year and cost category for the Digital-Hybrid Cloud and Data Center Migration project are in the table provided below.

Digital-Hybrid Cloud and Data Center Migration					
Case No. U-21870					
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**Total Company O&M**	**Electric Allocation O&M**	**U-21585 /U-21870 Reference**
2023 Actuals					
Software	$1,338,619	$909,190	$0	$0	U-21585, A-88 (SHB-6), line 85, columns l and r
Material	$378,526	$257,095	$0	$0	U-21585, A-88 (SHB-6), line 85, columns m and s
Labor	$228,285	$155,051	$143,377	$93,195	U-21585, A-88 (SHB-6), line 85, columns n and t
Contractor	$707,059	$480,234	$354,684	$230,545	U-21585, A-88 (SHB-6), line 85, columns o and u
Overheads & Other Costs	$126,525	$85,936	$30,771	$20,001	U-21585, A-88 (SHB-6), line 85, columns p and v
Total 2023 Actuals	**$2,779,013**	**$1,887,506**	**$528,832**	**$343,741**	U-21585, A-88 (SHB-6), line 85, columns k and q
2024 Actuals					
Software	$108,522	$75,586	$187,720	$118,264	U-21870, A-20 (SHB-5), line 58, columns m and t
Material	-$95,809	-$66,731	$21,695	$13,668	U-21870, A-20 (SHB-5), line 58, columns n and u
Labor	$791,688	$551,410	$212,277	$133,735	U-21870, A-20 (SHB-5), line 58, columns o and v
Contractor	$1,398,687	$974,186	$361,073	$227,476	U-21870, A-20 (SHB-5), line 58, columns p and w
Non-Labor Overhead	$0	$0	$0	$0	U-21870, A-20 (SHB-5), line 58, columns q and x
Non-Labor Other	$221,576	$154,328	$0	$0	U-21870, A-20 (SHB-5), line 58, columns r and y

Total 2024 Projected	**$2,424,664**	**$1,688,778**	**$782,765**	**$493,142**	U-21870, A-20 (SHB-5), line 58, columns l and s
2025 Projected					
Software	$180,000	$123,426	$0		U-21870, A-20 (SHB-5), line 149, columns m and t
Material	$0	$0	$0		U-21870, A-20 (SHB-5), line 149, columns n and u
Labor	$1,034,640	$709,453	$474,960	$294,383	U-21870, A-20 (SHB-5), line 149, columns o and v
Contractor	$0	$0	$0		U-21870, A-20 (SHB-5), line 149, columns p and w
Non-Labor Overhead	$147,714	$101,287	$33,247	$20,607	U-21870, A-20 (SHB-5), line 149, columns q and x
Non-Labor Other	$413,856	$283,781	$72,000	$44,626	U-21870, A-20 (SHB-5), line 149, columns r and y
Total 2025 Projected	**$1,776,210**	**$1,217,947**	**$580,207**	**$359,615**	U-21870, A-20 (SHB-5), line 149, columns l and s
Total Projected					
Software	$1,627,141	$1,108,202	$187,720	$118,264	
Material	$282,717	$190,364	$21,695	$13,668	
Labor	$2,054,612	$1,415,914	$830,614	$521,312	
Contractor	$2,105,746	$1,454,420	$715,757	$458,021	
Non-Labor Overhead	$208,915	$142,855	$33,247	$20,607	
Non-Labor Other	$700,756	$482,477	$102,771	$64,627	
Total Projected	**$6,979,887**	**$4,794,231**	**$1,891,804**	**$1,196,498**	

Q. What are the current projected total project costs broken down by year for the Digital-Hybrid Cloud and Data Center Migration project?

A. The total project costs broken down by year for the Digital-Hybrid Cloud and Data Center Migration project are in the table provided below.

Digital-Hybrid Cloud and Data Center Migration					
Case No. U-22070					
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**Total Company O&M**	**Electric Allocation O&M**	**U-21585, U-21870, and U-22070 Reference**
2023 Actuals					
Software	$1,338,619	$909,190	$0	$0	U-21585 A-88 (SHB-6), line 85, columns l and r
Material	$378,526	$257,095	$0	$0	U-21585 A-88 (SHB-6), line 85, columns m and s
Labor	$228,285	$155,051	$143,377	$93,195	U-21585 A-88 (SHB-6), line 85, columns n and t
Contractor	$707,059	$480,234	$354,684	$230,545	U-21585 A-88 (SHB-6), line 85, columns o and u
Overheads & Other Costs	$126,525	$85,936	$30,771	$20,001	U-21585 A-88 (SHB-6), line 85, columns p and v
Total 2023 Actuals	**$2,779,013**	**$1,887,506**	**$528,832**	**$343,741**	U-21585 A-88 (SHB-6), line 85, columns k and q
2024 Actuals					
Software	$108,522	$75,586	$187,720	$118,264	U-21870 A-20 (SHB-5), line 58, columns m and t
Material	-$95,809	-$66,731	$21,695	$13,668	U-21870 A-20 (SHB-5), line 58, columns n and u
Labor	$791,688	$551,410	$212,277	$133,735	U-21870 A-20 (SHB-5), line 58, columns o and v
Contractor	$1,398,687	$974,186	$361,073	$227,476	U-21870 A-20 (SHB-5), line 58, columns p and w
Non-Labor Overhead	$0	$0	$0	$0	U-21870 A-20 (SHB-5), line 58, columns q and x
Non-Labor Other	$221,576	$154,328	$0	$0	U-21870 A-20 (SHB-5), line 58, columns r and y

Total 2024 Actuals	**$2,424,664**	**$1,688,778**	**$782,765**	**$493,142**	U-21870 A-20 (SHB-5), line 58, columns l and s
2025 Actuals					
Software	$0	$0	$22,418	$13,895	U-22070 A-20 (SHB-5), line 60, columns m and t
Material	-$3,101	-$2,126	$0	$0	U-22070 A-20 (SHB-5), line 60, columns n and u
Labor	$1,291,285	$885,434	$112,209	$69,548	U-22070 A-20 (SHB-5), line 60, columns o and v
Contractor	$2,349,426	$1,611,001	$719,680	$446,061	U-22070 A-20 (SHB-5), line 60, columns p and w
Non-Labor Overhead	$0	$0	$0	$0	U-22070 A-20 (SHB-5), line 60, columns q and x
Non-Labor Other	$339,337	$232,683	$0	$0	U-22070 A-20 (SHB-5), line 60, columns r and y
Total 2025 Actuals	**$3,976,947**	**$2,726,992**	**$854,307**	**$529,504**	U-22070 A-20 (SHB-5), line 60, columns l and s
2026 Projected					
Software	$0	$0	$0	$0	U-22070 A-20 (SHB-5), line 143, columns m and t
Material	$0	$0	$0	$0	U-22070 A-20 (SHB-5), line 143, columns n and u
Labor	$366,190	$242,564	$33,006	$20,794	U-22070 A-20 (SHB-5), line 143, columns o and v
Contractor	$1,287,651	$852,940	$241,671	$152,253	U-22070 A-20 (SHB-5), line 143, columns p and w
Non-Labor Overhead	$0	$0	$0	$0	U-22070 A-20 (SHB-5), line 143, columns q and x
Non-Labor Other	$79,458	$52,633	$0	$0	U-22070 A-20 (SHB-5), line 143, columns r and y

Total 2026 Projected	**$1,733,299**	**$1,148,137**	**$274,677**	**$173,047**	U-22070 A-20 (SHB-5), line 143, columns l and s
Total Projected					
Software	$1,447,141	$984,776	$210,138	$132,158	
Material	$279,617	$188,238	$21,695	$13,668	
Labor	$2,677,447	$1,834,460	$500,869	$317,271	
Contractor	$5,742,822	$3,918,361	$1,677,108	$1,056,335	
Non-Labor Overhead	$61,201	$41,568	$0	$0	
Non-Labor Other	$705,694	$484,012	$30,771	$20,001	
Total Projected	**$10,913,923**	**$7,451,414**	**$2,440,581**	**$1,539,433**	

Q. Why have the projected costs of the Digital-Hybrid Cloud and Data Center Migration project changed from previous projections in Case No. U-21870?

A. The projected capital costs for the Digital-Hybrid Cloud and Data Center Migration project increased by $2.66 million in electric allocation from the projections presented in Case No. U-21870. This increase reflects higher contractor costs of $2.46 million, increased labor costs of $0.42 million, and increased non-labor other costs of $0.10 million, partially offset by decreases in software costs of $0.12 million and non-labor overhead of $0.10 million.

The primary cause of the $2.66 million capital increase is expansion in both project scope and technical complexity. First, the application and server migration scope increased significantly. The original 2026 plan included the migration of seven applications. However, due to carryover work from 2025 and the addition of new scope, the number of applications scheduled for migration in 2026 increased to twenty-six.

Second, application complexity increased due to integration challenges associated with the development of additional cloud platform components. These components include application and API gateways, enterprise service bus, and load balancers that manage traffic to Azure-hosted applications. These factors materially increased delivery effort,

integration scope, and resource requirements, necessitating additional capital investment to ensure successful implementation and long-term platform stability.

Contractor costs increased by $2.46 million due to the need for additional specialized cloud migration expertise and the expanded scope of migration activities. Labor costs increased by $0.42 million due to the assignment of additional internal employees to ensure quality deliverables were achieved through design, build, and additional testing cycles, and support of an extended project timeline.

In addition, projected O&M costs for the project increased by $0.34 million in electric allocation from the projections presented in Case No. U-21870. This increase reflects higher contractor costs of $0.60 million, partially offset by decreases in labor costs of $0.20 million, non-labor other costs of $0.04 million, and non-labor overhead of $0.02 million.

The primary driver of the $0.34 million O&M increase is the expanded application scope, increased technical complexity, and higher post-go-live support requirements. The growth in applications from seven to twenty-six substantially increased ongoing operational workload and resource needs. In addition, the introduction of new cloud platform components, including application and API gateways, enterprise service bus, and load balancers, increased integration complexity and operational support demands.

Following implementation, the larger and more complex application environment increases ongoing O&M requirements, including enhanced monitoring, incident management, performance tuning, and stabilization activities during the early post go-live period. These factors require additional resources and sustained investment to ensure reliable operations and long-term platform stability.

Q. Please explain the Security/OT Field Modernization project.

A. The Security/OT Field Modernization project requires no capital expenditures and O&M expenses in the test year and has the following synopsis:

- **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.
- **Problem Statement:** Gas and Gas 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. The 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; and (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.

Q. What were the total projected capital expenditures for the Security/OT Field Modernization in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the Security/OT Field Modernization project are in the table provided below.

Security/OT Field Modernization			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 Reference**
2025 Projected			
Software	$0	$0	A-20 (SHB-5), line 171, column m
Material	$284,800	$195,287	A-20 (SHB-5), line 171, column n
Labor	$341,200	$233,961	A-20 (SHB-5), line 171, column o
Contractor			A-20 (SHB-5), line 171, column p
Non-Labor Overhead	$23,884	$16,377	A-20 (SHB-5), line 171, column q
Non-Labor Other	$185,235	$127,015	A-20 (SHB-5), line 171, column r
Total 2025 Projected	**$835,119**	**$572,641**	A-20 (SHB-5), line 171, column l
2026 Projected			
Software	$0	$0	A-20 (SHB-5), line 245, column m
Material	$123,200	$84,478	A-20 (SHB-5), line 245, column n
Labor	$125,300	$85,918	A-20 (SHB-5), line 245, column o
Contractor	$0	$0	A-20 (SHB-5), line 245, column p
Non-Labor Overhead	$8,771	$6,014	A-20 (SHB-5), line 245, column q
Non-Labor Other	$69,178	$47,436	A-20 (SHB-5), line 245, column r
Total 2026 Projected	**$326,449**	**$223,846**	A-20 (SHB-5), line 245, column l
Total Projected			
Software	$0	$0	
Material	$408,000	$279,766	
Labor	$466,500	$319,879	
Contractor	$0	$0	
Non-Labor Overhead	$32,655	$22,392	
Non-Labor Other	$254,413	$174,451	
Total Projected	**$1,161,568**	**$796,487**	

Q. What are the current projected total project costs broken down by year for the Security/OT Field Modernization project?

A. The total project costs broken down by year for the Security/OT Field Modernization project are in the table provided below.

Security/OT Field Modernization			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-22070 Reference**
2025 Actuals			
Software	$32,072	$21,992	A-20 (SHB-5), line 62, column m
Material	$775,632	$531,851	A-20 (SHB-5), line 62, column n
Labor	$195,349	$133,951	A-20 (SHB-5), line 62, column o
Contractor	$120,153	$82,389	A-20 (SHB-5), line 62, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 62, column q
Non-Labor Other	$51,742	$35,479	A-20 (SHB-5), line 62, column r
Total 2025 Actuals	**$1,174,948**	**$805,662**	A-20 (SHB-5), line 62, column l
2026 Projected			
Software	$121,672	$80,596	A-20 (SHB-5), line 145, column m
Material	$0	$0	A-20 (SHB-5), line 145, column n
Labor	$381,321	$252,587	A-20 (SHB-5), line 145, column o
Contractor	$350,548	$232,203	A-20 (SHB-5), line 145, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 145, column q
Non-Labor Other	$89,077	$59,005	A-20 (SHB-5), line 145, column r
Total 2026 Projected	**$942,618**	**$624,390**	A-20 (SHB-5), line 145, column l
Total Projected			
Software	$153,744	$102,588	

Material	$775,632	$531,851	
Labor	$576,670	$386,538	
Contractor	$470,700	$314,591	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$140,819	$94,484	
Total Projected	**$2,117,565**	**$1,430,052**	

Q. Why have the projected costs of the Security/OT Field Modernization project changed from previous projections in Case No. U-21870?

A. The projected capital costs for the Security/OT Field Modernization project increased by $0.63 million in electric allocation from the projections presented in Case No. U-21870. This increase is due to higher software costs of $0.10 million, material costs of $0.25 million, labor costs of $0.06 million, and contractor costs of $0.31 million, partially offset by decreases in non-labor overhead of $0.02 million and non-labor other costs of $0.08 million.

The primary driver of the capital increase is the need for additional field devices and enhanced network security capabilities identified during project execution. The project required additional devices, including higher-cost rugged Toughbooks, as well as routers necessary to connect field equipment to a secure network, which were not fully accounted for in the original estimates.

Software costs increased due to need for NetMotion licenses that were not included in the original projected costs. NetMotion is a secure remote access and mobile performance management platform that enables field workers to connect to the Company's network safely and reliably. Material costs increased due to additional hardware requirements and updated security specifications. Contractor costs increased due to unanticipated application packaging complexity and volume, requiring specialized external

resources. Labor, non-labor overheads, and non-labor other costs decreased as work shifted from internal resources to contractor support.

Q. Please explain the OT Datacenter Migration project.

A. The OT Datacenter Migration project has the following synopsis:

- The **OT Datacenter Migration** project requires $1,482,976 in capital ($1,186,381 ROM Adjusted Capital) and $399,966 in O&M in the test year.
    - **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.
    - **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.

Q. If the OT Datacenter Migration project were approved, would the Company be able to avoid costs in the ARP-OT Support Common and ARP-OT Support Electric projects in future years?

A. Yes. If the OT Datacenter Migration project were approved, the Company would be able to avoid ARP-OT Support Common and ARP-OT Support Electric project costs in 2027.

Project	Total Company	
	Capital	O&M
ARP-OT Support Common	$809,200	$83,440
ARP-OT Support Electric	$828,600	$87,120

Q. In the Commission's September 30, 2025 Order in Case No. U-21806, pages 126-130, did the Commission disallow the OT Datacenter Migration project?

A. Yes. The Commission disallowed the OT Datacenter Migration project indicating that insufficient justification for why relocating the datacenter to co-location vendor facility is cost-effective and reasonable option in comparison to fixing the aging climate control equipment and continuing water filtration issues with the existing building. The Commission also agreed that this project could be shown to be reasonable and prudent with additional supporting evidence in a future case.

Q. Does the Company have any additional supporting evidence for why relocating the OT datacenter to a co-location vendor facility is cost-effective and reasonable option

in comparison to fixing the aging climate control equipment and continuing water filtration issues with the existing building?

A. Yes. The Company has estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the current location to be $5,082,728. The projected costs to replace the aging climate control equipment including labor is $4,965,728. To remediate the water infiltration issue it would require removal of architectural concrete and replacing the waterproof membrane, which is estimated to be $117,000. This does not address the risk of the datacenter location being in the basement of the Parnall building near the main water pipe for the building. By moving the data center to a new co-located facility, this cost would be avoided and mitigate the risk of the location of the datacenter being near the main water pipe for the building.

Q. In the Commission's March 27, 2026 Order in Case No. U-21870, pages 208-211, did the Commission allow the OT Datacenter Migration project?

A. Yes. The Commission allowed the OT Datacenter Migration project agreeing with the Administrative Law Judge's ("ALJ") recommendation to reject the Attorney General's disallowance. The ALJ found that the Company sufficiently supported the project and that the Company had responded to the Commission's directive in the September 30, 2025 Order in Case No. U-21806 to provide the costs of remaining in the basement of the Parnall building and explain why a railway line near the building was problematic for the datacenter.

Q. Please explain the SAP S/4HANA Implementation project.

A. The SAP S/4HANA Implementation project has the following synopsis:

- The **SAP S/4HANA Implementation** project requires $14,025,179 in capital ($11,220,143 ROM Adjusted Capital) in the test year.

- **Description:** This project will modernize our current SAP ERP solution. Upon completion, the solution will provide enhanced functionality across several business areas while providing a supported and secure platform capable of business transformation.

- **Problem Statement:** The current SAP ERP system will reach the end of mainstream vendor maintenance on December 31, 2027. Operating the system beyond the end of support date creates significant risks to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber protection against customer and employee data breaches. In addition, an unsupported platform limits improvement of operational efficiency and maintaining the stability, reliability, and security of the system.

- **Objectives:** The S/4HANA program will position the Company for business transformation by enabling it to (1) provide and maintain capabilities for protection of sensitive customer and employee data; (2) provide enhanced system stability and reliability needed in a 24x7 business by significantly reducing system maintenance outages; (3) mitigate the regulatory and operational risks of running critical business processes on an unsupported platform; (4) implement simplified workflows and standardized processes by reducing customizations; and (5) use in-memory computing with embedded real-time analytics to make smarter, faster decisions.

- **Scope:** The project scope includes (1) Migrating the current SAP ERP solution to the latest S/4HANA solution. This includes (a) moving to the latest version of the software (b) migrating existing data to the new S/4HANA data model (c) connecting interfaces from other systems into S/4HANA (d) using newer user interfaces available in S/4HANA where feasible (e) setting up users and user access in the new system (f) migrating existing reports and analytics or replacing them with new in-built reports and analytics in S/4HANA and (g) implementing the solution on Azure cloud. (2) Enabling an architecture that minimizes downtime for system maintenance activities. (3) Implementing solutions where existing SAP ERP functionality is not available in S/4HANA. (4) Implementing a foundational "clean core framework". This requires minimizing or remediating custom code and utilizing SAP customization best practices in the new version. These best practices will decouple the core SAP software from company-specific customizations, hence making it ”clean.” This clean core framework is expected to reduce the effort and cost of upgrading SAP in subsequent releases.

- **Alternatives:** An analysis was completed that included key industry input, feedback from business areas across the company, technology leaders, and

subject matter experts. This presented the organization with several alternatives, including the following: (1) Postpone the decision and stay on the current version. This would require purchasing the extended maintenance until 2030 due to the current mainstream maintenance expiring in December 2027. A skill shortage is anticipated as SAP customers scramble to meet the 2030 deadline. Delaying our decision to migrate to S/4HANA would put the Company at a higher risk of securing those high-demand skilled resources. Staying on the current version beyond 2030 with third party support would limit the Company's ability to continuously improve operational efficiency and maintain the stability, reliability, and security of the system. This alternative was not selected because of the additional cost and risk, and the inability for the Company and its customers to enjoy any added benefits or new application features. (2) Eliminate SAP and use multiple best of breed solutions in the various business areas. (3) Eliminate SAP and implement a new ERP solution. SAP is currently used across the Corporate, Work and Asset Management, and Customer areas. There are very limited options for a single ERP system that provides all three areas of functionality. The current SAP system has over a hundred satellite systems and around a thousand interfaces. Non-SAP alternatives may not work with current satellite systems, requiring the replacement or significant remediation of those satellite systems. These non-SAP alternatives would require a much larger change management initiative, significant reskilling of technical resources, and retraining of people across the Company who have become familiar with SAP over the last sixteen years. Alternatives (2) and (3) are more expensive, complex to implement and support long-term, therefore were not chosen. (4) Migrate to the latest S/4HANA solution before the end of 2030. This option was chosen because it mitigates risks and provides a supported and secure platform capable of business transformation.

Q. Describe the deployment approach the Company will utilize for the SAP S/4HANA Implementation project.

A. The Company will deploy the migration to the new S/4HANA solution in phases to reduce the risk of operational impact to customers and co-workers. The Company will adopt SAP's standard Activate methodology for the deployment approach.[6] The Activate methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and

[6] Available at SAP Activate | Deployment and Implementation of SAP S/4HANA Cloud.

Run/Adopt. The Discover, Prepare, and Explore phases result in the design, which is then built, tested, and deployed in the Realize, Deploy, and Run/Adopt phases. The approach is to design the system holistically, meaning the Discover, Prepare, and Explore phases will cover all modules of SAP, including Finance, Supply Chain, HR, Work Management, and Customer. This ensures the system is designed optimally from end to end. Once the design is complete, the Company will conduct multiple iterations of the Realize, Deploy, and Run phases to deploy functional modules in a staggered capability deployment approach. The functional modules will be bundled into releases that minimize risk, complexity, and effort. The scope and schedule for each release is being determined in partnership with the system integrator. The approach is to bundle the essential scope needed to get to S/4HANA in the first release targeted for mid-2027, followed by subsequent releases.

Q. Please explain the different S/4HANA migration alternatives considered.

A. The Company considered three migration alternatives: (1) Build a new SAP system without using any existing customizations, configurations, processes, or data (Greenfield); (2) Upgrade the existing SAP system, retaining existing customizations, processes, and data, then remediate errors that arise in the upgrade process in a series of iterations (Brownfield); and (3) Adopt a hybrid strategy, building a new SAP system, while selectively migrating critical data and process from the existing system (Bluefield).

Q. Which S/4HANA migration approach has the Company selected?

A. The Company has selected the hybrid or Bluefield approach for the S/4HANA Implementation project.

Q. Why did the Company select the Hybrid, or Bluefield, migration approach for the S/4HANA Implementation project and not the others?

A. The Company chose the Hybrid, or Bluefield, approach because it offers the best balance of lower risk and cost.[7] While the Greenfield option provides lower total-cost-of-ownership and faster time-to-value for implementations that want to shed a lot of legacy customizations and start afresh, this is not fully the case for the Company because the current system has many essential customizations in the customer billing and employee payroll areas that will need to be rewritten in the new system with this approach. Rebuilding customizations introduces significant risk and cost. Similarly, the Brownfield approach could provide a shorter project timeline by migrating all the current customizations and processes. However, this approach is not preferred in the Finance, Supply Chain, and Work Management areas where the current system has a lot of custom processes, workflows, enhancements, and interfaces that are suboptimal compared to the standard best practice processes that come in S/4HANA. The Brownfield approach is also not preferred because the processes and data model in Finance and Supply Chain have changed significantly. Upgrading current customizations to the new system would not be easy and rewriting them would be expensive and increase risk. This would result in a new system that does not conform to SAP's clean core approach and would be expensive to upgrade in the future. Therefore, the ideal approach is a combination of the two where the new system adopts a Greenfield approach for Finance, Supply Chain and Work Management, and a Brownfield-like approach for Customer and Payroll.

[7] Available at https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach

Q. Why is the Company undertaking the expense and effort of migrating to the SAP S/4HANA version at this time?

A. Migrating to the SAP S/4HANA version is crucial for the Company because the mainstream support for our current SAP version ends in December 2027. After evaluating the project, the Company determined it will take approximately three years to complete. The Company began the project in 2025 and the timeline will extend into 2028, requiring the Company to purchase extended SAP support for 2028. It is important to note that extended support for the Company's current SAP licensed version is only available until 2030. Recently, SAP announced that customers can purchase extended support through 2033, but only if they commit to migrating to S/4HANA using a RISE with SAP cloud subscription. The extended support options are intended to give companies more time to transition, not to provide a reason to delay the migration.

Q. Will the Company's SAP systems face an increased risk of cyber-attacks if the S/4HANA project is not executed?

A. Yes. The Company's SAP systems will face increased risk of cyber-attacks if the S/4HANA project is not executed, because SAP has stated that after maintenance ends, standard patches will no longer be available for SAP customer-specific maintenance, leaving the Company's SAP systems vulnerable to emerging threats from bad actors exploiting known vulnerabilities.[8]

[8] Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364.

Q. Please explain whether the Company's SAP systems will continue to operate if the S/4HANA project is not executed?

A. The Company's SAP systems will continue to operate with significant risk for an indeterminate period of time if the S/4HANA project is not executed. SAP will not support the Company's current SAP version after December 2027, when the mainstream maintenance ends. After this period, the risk of operational disruptions will increase significantly due to the lack of a Service Level Agreement with SAP, and there will be no guarantee that SAP resolve any new issues that arise.

Q. Please explain which SAP S/4HANA licensing options the Company considered.

A. The Company considered the two licensing options offered by SAP: Bring Your Own License ("BYOL") and RISE with SAP. The first licensing option considered was BYOL, which would provide the Company perpetual licenses to use the S/4HANA software in a hosted cloud or Company owned data center. The second licensing option considered was RISE with SAP, which would provide the Company a cloud subscription to S/4HANA software that is hosted and managed by SAP.

Both licensing options have comparable total costs of ownership over a period of 15 years (until 2040 based on SAP's stated roadmap of support for S/4HANA).

Q, Please explain which SAP S/4HANA licensing option the Company has selected.

A. The Company has selected the RISE with SAP licensing option. SAP is focusing future innovations, specifically AI capabilities, on RISE with SAP. By positioning itself as a cloud company, SAP is strongly encouraging customers to choose the RISE model to take advantage of their investment in AI innovations. SAP reports that 15 utilities have already migrated to the RISE with SAP option, and another 27 utilities are currently migrating.

Q. In the Commission's March 27, 2026 Order in Case No. U-21870, pages 192-196 and 246-247, did the Commission approve special rate-making treatment to amortize the cloud implementation costs for the SaaS solutions and defer the Investments O&M expense associated with the SAP S/4HANA Implementation project over a 15-year asset life?

A. Yes. The Commission approved the Company's proposal to amortize the cloud implementation costs for the SaaS solutions and defer the Investments O&M expense associated with the SAP S/4HANA Implementation project over a 15-year asset life, in order to minimize the impact on rates.

Q. Please describe Confidential Exhibit A-28 (SHB-13).

A. Confidential Exhibit A-28 (SHB-13) is the Projected 13-Month Average of IT S/4HANA Regulatory Asset for the projected years 2027 – 13-month balance ending April 30, 2028. It provides a summary of the electric allocation of projected deferred IT Investments O&M expense associated with the SAP S/4HANA Implementation project. Specifically:

- Column (a) provides the S/4HANA category;
- Columns (b) through (n) provide each month's ending IT S/4HANA Regulatory Asset balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Confidential Exhibit A-28 (SHB-13).

A. To support the deferral of IT Investments O&M associated with the SAP S/4HANA Implementation project. Investments costs are projected based on current cost estimates for the project. The Company is adjusting working capital to reflect these projections, which is shown in Company witness Patton's Exhibit A-12 (HLP-34), Schedule B-4.

Q. What is the Company proposing for the amortization of the special rate-making for the SAP S/4HANA Implementation project?

A. The Company is proposing that the 15-year amortization for the cloud implementation costs for the SaaS solutions and deferred Investments O&M expense associated with the SAP S/4HANA Implementation begin after the Company completes all releases for the project and after Staff and Intervenors review the total deferred expenses for reasonableness and prudence. This proposal will be discussed further in the direct testimony of Company witness Patton.

Q. Do Generally Accepted Accounting Principles ("GAAP") and FERC have separate accounting guidance to account for cloud subscription and cloud implementation costs that do not meet capitalization requirements to take possession without significant penalty?

A. GAAP and FERC have the same accounting guidance for cloud subscriptions when the contract does not provide the ability to take possession of the software without significant penalty (meet capitalization requirements).

GAAP and FERC do have separate accounting guidance to account for cloud implementation costs when the contract does not provide the ability to take possession of the software without significant penalty (meet capitalization requirements).

Under GAAP, for cloud implementation costs associated with a contract that does not meet capitalization requirements to take possession without significant penalty, are capitalized to other assets, not Property, Plant and Equipment ("PPE"), then amortized over the remaining life of the contract.

Under FERC, for cloud implementation costs associated with a contract that does not meet capitalization requirements to take possession without significant penalty, are capitalized to PPE, then amortized over the remaining life of the contract.

Q. Did the Company, in previous Case No. U-21870, present cloud implementation costs for SaaS solutions associated with the SAP S/4HANA Implementation project based on GAAP rather than FERC reporting?

A. Yes. The Company, in previous Case No. U-21870 presented cloud implementation costs for SaaS solution associated with the SAP S/4HANA Implementation project based on GAAP rather than FERC reporting. The Company specifically provided in Case No. U-21870, Exhibit A-26 (SHB-11), which was the IT S/4HANA Cloud Implementation Costs balance for Electric and Common investments for the projected 13 months ending April 30, 2027.

Q. Is the Company correcting its presentation of the cloud implementation costs for SaaS solutions associated with the SAP S/4HANA Implementation project based on FERC reporting in this case?

A. Yes. The Company is correcting its presentation of the cloud implementation costs for SaaS solutions associated with the SAP S/4HANA Implementation project as capital expenditures in accordance with FERC reporting. The projected electric allocation costs for this Case No. U-22070 have been provided in Confidential Exhibit A-21 (SHB-6) and the Total Company Expected Project Costs are provided in Confidential Exhibit A-29 (SHB-14).

Q. Please describe Confidential Exhibit A-29 (SHB-14).

A. **Confidential** Exhibit A-29 (SHB-14) is the total expected project costs for the SAP S/4HANA costs for Electric and Common investments for all years by cost category. It provides a reconciliation of the total Company projected total project costs from the previous Case No. U-21870 and this case. Specifically:

- Column (a) provides the cost category;
- Column (b) provides the Total Company Expected Project capital costs at the time of Case No. U-21870;
- Column (c) provides the Total Company Expected Project Cloud Implementation costs at the time of Case No. U-21870;
- Column (d) provides the Total Company IT Investments O&M at the time of Case No. U-21870;
- Column (e) is the sum of columns (b), (c), and (d) and provides the Total Company Expected Project costs at the time of Case No. U-21870;
- Column (f) provides the Total Company Expected Project capital costs at the time of this Case No. U-22070;
- Column (g) provides the Total Company Expected Project deferred IT Investments O&M costs at the time of this Case No. U-22070;
- Column (h) provide the Total Company Expected Project O&M costs projected to not be recovered through rates at the time of this Case No. U-22070. This will be discussed further later in my direct testimony;
- Column (i) is the sum of columns (f), (g), (h) and provides the Total Company Expected Project costs at the time of this Case No. U-22070; and
- Column (j) provides the variance of the Total Company Expected Projects Costs between Case No. U-21870 and this Case No. U-22070.

Q. How did the Company develop the initial cost estimate for the SAP S/4HANA Implementation project?

A. The Company developed the initial cost estimate for the SAP S/4HANA Implementation project with the support of an independent third party that specializes in preparing for

S/4HANA upgrades. The cost estimate consists of labor, contractor, software, and non-labor costs.

The labor and contractor cost estimates were derived as follows:

- First, the phases of the project were laid out in a timeline based on the phased deployment approach and Hybrid migration approach, both previously described in my testimony.
- Second, the high-level scope was identified, including the processes, pain points, customizations, integrations, roles, and data volumes that need to be migrated to S/4HANA.
- Third, the effort for the design and subsequent phases were translated into the number of hours and resources required for each phase. The resources are further broken down into roles and number of each role.
- Lastly, the resource estimates were assumed to be a mix of 30% internal employees and 70% external contractors. The Company then applied an average resource rate based on internal and external resources to calculate the cost estimate. For certain activities, the resource estimate was derived using a percentage of the overall effort based on best practices, e.g. program management and quality management.
    - The software cost estimate was based on indicative Bill of Material ("BOM") from SAP for BYOL.
    - The non-labor cost estimates are based on business expense, and labor overheads based on projected internal labor and external contractor costs to support the project.

Finally, the Company conducted a comparison of peer utility overall cost estimates and duration for their S/4HANA implementation projects to validate the Company's overall cost and duration estimate was reasonable.

Q. Has the Company revised the cost estimate for the SAP S/4HANA Implementation project in this case?

A. Yes. The Company has revised the costs estimate based on the selection of the RISE with SAP cloud subscription licensing and updated estimates for external and internal labor based on Request for Proposal ("RFP") from the System Integrator ("SI").

First, the cost estimate was revised to reflect selecting the RISE with SAP cloud subscription licensing option, which is based on an initial BOM from SAP adjusted for negotiated savings. This reduced total project software costs by $46 million (Confidential Exhibit A-29 (SHB-14), column j, line 29) and a portion of the total project Non-Labor Other costs by $5 million (Confidential Exhibit A-29 (SHB-14), column j, line 34) that was planned for cloud hosting services.

Second, based on the RFP from the SI, the estimates for internal labor and external contractor costs were refined. Based on discussions with SI, the deployment and release plan have changed from the initial estimate and requires more effort than originally planned. The Company is in the final stages of contracting with the SI. This resulted in a total project internal labor costs increase of $13 million (Confidential Exhibit A-29 (SHB-14), column j, line 31). The Company also worked with selected SI to identify other external services and products required to remediate non-SAP applications that integrate with SAP, provide functional subject matter expertise, design validation, data cleansing, and governance support. The additional effort to support the deployment and release plan and additional external services resulted in a total project contractor costs increase of $41 million (Confidential Exhibit A-29 (SHB-14), column j, line 32) offset by the recategorization of the total project Non-Labor Overhead costs by $5 million (Confidential Exhibit A-29 (SHB-14), column j, line 34) due to IT Administration Allocation to support employees and contractors now being mapped to either labor or contractor cost categories in this case.

Q. Is there a portion of the SAP S/4HANA Implementation project costs that the Company is projecting will not be recovered through customer rates?

A. Yes. Due to the need to accelerate the start of the SAP A/4HANA Implementation project, the Company is projecting that approximately $31 million (Confidential Exhibit A-29 (SHB-14), column j, line 32) of costs will not be recovered through customer rates. These expenses were incurred or are expected to be incurred prior to the approval of special ratemaking treatment that permits deferral of such costs to a regulatory asset. Specifically, approximately $10 million relates to project expenses incurred before November 1, 2025, the effective date of the deferral mechanism approved in the Company's most previous gas rate case (Case No. U-21806). The remaining $19 million is projected to be incurred before May 1, 2026, the proposed effective date of the deferral mechanism approved in the Company's electric rate case (Case No. U-21870). As these expenses fall outside the scope of the approved or anticipated deferral treatment, they are not expected to be recovered through customer rates and therefore, have no impact on the revenue requirement calculation in the instant case.

Q. Why is this SAP upgrade more costly than the Company's previous upgrades?

A. This SAP upgrade is more costly than the Company's previous upgrades for several reasons. First, the latest SAP S/4HANA version improves business processes, requiring the Company to thoroughly evaluate these best practices against existing processes. This evaluation is crucial in determining adoption and adds to the overall project cost.

Second, migrating data to the new system involves mapping, transforming, and testing data elements required by S/4HANA's new data model. Third, the Company must re-evaluate and update user access because the system controlling access permissions has

changed in S/4HANA. Fourth, the existing solution has customizations that cannot be moved to the new system as-is due to the differences in business processes, data model, and permissions. Finally, SAP recommends customers adopt a "clean core" approach when customizations are necessary. This approach moves the customizations outside the core product, which makes future upgrades easier. This requires the Company to perform a detailed evaluation and remediation of existing customizations.

Q. Would it be more cost-effective for the Company to replace its SAP systems?

A. No. It would not be more cost-effective for the Company to replace its SAP systems. This would require re-engineering the entire SAP system to a new solution, assuming that the current system could be replaced with a single replacement. It would require significant effort to re-skill the Company's co-workers, re-engineer business processes, re-implement the system, and integrate the new system with all the systems currently interfacing with SAP. The Company currently has more than 1,000 interfaces to SAP. Replacing SAP with multiple systems would be more costly and introduce additional risk due to the complexity of managing multiple disparate solutions. The Company would need to develop integrations between systems like Finance, Supply Chain, Work Management, and Customer. These integrations are inherent in an integrated solution such as SAP.

Q. In the Commission's September 30, 2025 Order in Case No. U-21806, pages 106-107, did the Commission advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency?

A. Yes. The Commission did advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency or, if the

Company believes it is necessary to do so, to at least provide a detailed explanation of the reason for confidential treatment on the record.

Q. Why did the Company classify the capital expenditures and O&M expense amounts related to the SAP S/4HANA Implementation project as confidential?

A. The Company classified the capital expenditures and O&M expense amount related to the SAP S/4HANA Implementation project as confidential due to the impact of publicly disclosing the total projected costs of the project. Publicly disclosing the total projected project costs would impact the Company's ability to competitively bid contractor and software costs, impacting the cost-effectiveness of the project for customers.

Q. Does the Company intend to maintain the confidentiality of its test year capital expenditures, O&M expense, and cloud implementation costs in this case?

A. No. Given the Commission's advisement, the Company does not intend to maintain the confidentiality of its test year capital expenditures, O&M expense and cloud implementation costs in this case.

Q. Does the Company intend to maintain the confidentiality of total projected capital expenditures, deferred Investments O&M expense and other costs in this case?

A. Yes. The Company does intend to maintain the confidentiality of its total projected capital expenditures, deferred Investments O&M expense and other costs in this case for the reasons I described above.

Q. In the Commission's September 30, 2025 Order in Case No. U-21806, page 307, and its March 27, 2026 Order in Case No. U-21870, page 196, did the Commission impose any additional requirements regarding the SAP S/4HANA Implementation project?

A. Yes. The Commission directed the Company to meet quarterly with MPSC Staff to report on the SAP S/4HANA Implementation project's progress. These updates must include information on project implementation milestones, budget adherence, scope changes, and other relevant developments. Additionally, the Commission ordered the Company to "record any over recovery or under recovery of each projected expense associated with the project as compared to the 80% base that the Company expects to include in any future natural gas rate case until the project is complete."

Q. How has the Company addressed the Commission's requirements related to the SAP S/4HANA Implementation project from Case No. U-21806 and U-21870?

A. The Company values the opportunity to provide regular updates to MPSC Staff and has held two quarterly meetings in December 2025 and March 2026. These meetings will continue on a quarterly basis in accordance with the Commission's directive.

Regarding the tracking of "over or under recovery," the Company notes that in Case No. U-21870, none of the SAP project's capital expenditures were projected to be placed into service during the test year. As a result, current rates do not include any related depreciation expense, and the return on construction work in progress is offset by AFUDC. In short, there is no SAP S/4HANA Implementation project revenue requirement embedded in current rates for which an over or under recovery can be recorded.

Q. Are there any Digital Foundations and Capabilities projects that you would like to discuss?

A. Yes. The following Digital Foundations and Capabilities project is addressed below.

- SAP HANA Database Migration

Q. Please explain the SAP HANA Database Migration project.

A. The SAP HANA Database Migration project requires no capital expenditures and O&M expenses for the projected test year and has the following synopsis:

- **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.

- **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[9], 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

[9] Refer to my testimony, page 143, lines 9 through 18, for more information on SAP support being extended in limited circumstances.

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 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.

Q. What were the total projected capital expenditures for the SAP HANA Database Migration in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the SAP HANA Database Migration project are in the table provided below.

SAP HANA Database Migration			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21585 / U-21870 Reference**
2023 Actuals			
Software	$2,222,855	$1,509,763	U-21585, A-88 (SHB-6), line 87, column l
Material	$0	$0	U-21585, A-88 (SHB-6), line 87, columns m
Labor	$39,445	$26,791	U-21585, A-88 (SHB-6), line 87, column n
Contractor	$103,037	$69,983	U-21585, A-88 (SHB-6), line 87, column o
Overhead & Other Costs	$26,238	$17,821	U-21585, A-88 (SHB-6), line 87, column p

Total 2023 Actuals	**$2,391,575**	**$1,624,358**	U-21585, A-88 (SHB-6), line 87, column k
2024 Actuals			
Software	$306,891	$213,750	U-21870, A-20 (SHB-5), line 59, column m
Material	$351,637	$244,915	U-21870, A-20 (SHB-5), line 59, column n
Labor	$441,821	$307,729	U-21870, A-20 (SHB-5), line 59, column o
Contractor	$1,456,047	$1,014,137	U-21870, A-20 (SHB-5), line 59, column p
Non-Labor Overhead	$0	$0	U-21870, A-20 (SHB-5), line 59, column q
Non-Labor Other	$284,527	$198,173	U-21870, A-20 (SHB-5), line 59, column r
Total 2024 Projected	**$2,840,923**	**$1,978,703**	U-21870, A-20 (SHB-5), line 59, column l
2025 Projected			
Software	$0	$0	U-21870, A-20 (SHB-5), line 150, column m
Material	$0	$0	U-21870, A-20 (SHB-5), line 150, column n
Labor	$184,284	$126,364	U-21870, A-20 (SHB-5), line 150, column o
Contractor	$1,261,831	$865,238	U-21870, A-20 (SHB-5), line 150, column p
Non-Labor Overhead	$88,328	$60,567	U-21870, A-20 (SHB-5), line 150, column q
Non-Labor Other	$151,948	$104,190	U-21870, A-20 (SHB-5), line 150, column r
Total 2025 Projected	**$1,686,391**	**$1,156,358**	U-21870, A-20 (SHB-5), line 150, column l
Total Projected			
Software	$2,529,747	$1,723,513	
Material	$351,637	$244,915	
Labor	$665,551	$460,883	
Contractor	$2,820,914	$1,949,357	
Non-Labor Overhead	$104,943	$71,852	
Non-Labor Other	$446,097	$308,899	
Total Projected	**$6,918,889**	**$4,759,419**	

Q. What are the current projected total project costs broken down by year for the SAP HANA Database Migration project?

A. The total project costs broken down by year for the SAP HANA Database Migration project are in the table provided below.

SAP HANA Database Migration			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21585/U-21870/U-22070 Reference**
2023 Actuals			
Software	$2,222,855	$1,509,763	U-21585, A-88 (SHB-6), line 87, column l
Material	$0	$0	U-21585, A-88 (SHB-6), line 87, columns m
Labor	$39,445	$26,791	U-21585, A-88 (SHB-6), line 87, column n
Contractor	$103,037	$69,983	U-21585, A-88 (SHB-6), line 87, column o
Overhead & Other Costs	$26,238	$17,821	U-21585, A-88 (SHB-6), line 87, column p
Total 2023 Actuals	**$2,391,575**	**$1,624,358**	
2024 Actuals			
Software	$306,891	$213,750	U-21870, A-20 (SHB-5), line 59, column m
Material	$351,637	$244,915	U-21870, A-20 (SHB-5), line 59, column n
Labor	$441,821	$307,729	U-21870, A-20 (SHB-5), line 59, column o
Contractor	$1,456,047	$1,014,137	U-21870, A-20 (SHB-5), line 59, column p
Non-Labor Overhead	$0	$0	U-21870, A-20 (SHB-5), line 59, column q
Non-Labor Other	$284,527	$198,173	U-21870, A-20 (SHB-5), line 59, column r
Total 2024 Actuals	**$2,840,923**	**$1,978,703**	
2025 Actuals			
Software	$0	$0	U-22070, A-20 (SHB-5), line 61, column m
Material	$27,676	$18,977	U-22070, A-20 (SHB-5), line 61, column n

Labor	$341,949	$234,474	U-22070, A-20 (SHB-5), line 61, column o
Contractor	$2,895,366	$1,985,352	U-22070, A-20 (SHB-5), line 61, column p
Non-Labor Overhead	$0	$0	U-22070, A-20 (SHB-5), line 61, column q
Non-Labor Other	$165,523	$113,499	U-22070, A-20 (SHB-5), line 61, column r
Total 2025 Actuals	**$3,430,513**	**$2,352,303**	U-22070, A-20 (SHB-5), line 61, column l
Total Actuals			
Software	$2,529,747	$1,723,513	
Material	$379,312	$263,892	
Labor	$823,215	$568,994	
Contractor	$4,454,449	$3,069,471	
Non-Labor Overhead	$16,615	$11,285	
Non-Labor Other	$459,672	$318,208	
Total Projected	**$8,663,011**	**$5,955,363**	

Q. Why have the projected costs of the SAP HANA Database Migration project changed from previous projections in Case No. U-21870?

A. The reasons for the $1.20 million electric allocation increase in the SAP HANA Database Migration project capital costs from the projections presented in Case No. U-21870 are due to increases in contractor costs ($1.12 million), labor ($0.11 million), material ($0.02 million), and non-labor other ($0.01 million), offset by decreases in non-labor overhead ($0.06 million). The primary reason for the $1.20 million capital increase for these reasons: (1) the Company made the decision to stagger the migration across 2024 and 2025 to mitigate risk. By migrating ancillary systems to HANA in 2024, to gain valuable insight before migrating the ECC, it provided time to conduct mock migrations for ECC, which helped to minimize downtimes. (2) The project changed the migration approach and identified necessary infrastructure and execution activities that were not previously budgeted. The phased, staggered migration requires additional validation cycles and labor.

SAP HANA conversion and the Azure transition require specialized cloud architecture, virtual machines and licensing; and the project engaged on-site vendor technical assurance to reduce cutover failure risk. These additions shorten and reduce the likelihood of production downtime at cutover, materially shorten time-to-restore for critical incidents, and deliver a supported, scalable, high-performance cloud platform that lowers future remediation and operating expense.

Security Projects

Q. Please explain the Security projects.

A. Below are the Security projects:

- The **Critical Substation Upgrade** project requires $4,585,250 in capital ($3,668,200 ROM Adjusted Capital) and $374,500 in O&M in the test year.
    - **Description:** This project will implement enhanced security measures at the Company's critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity through real-time detection and increase the reliability of electric delivery to our customers.
    - **Problem Statement:** Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substation increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow us to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable.
    - **Objectives:** The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability.

- **Scope:** Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment etc.; (7) additional facility lighting; and (8) security equipment maintenance.
- **Alternatives:** Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the site. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time; (2) hiring contract security guards to patrol the sites. This alternative was not selected as ongoing O&M costs would be expensive; (3) outfitting sites with thermal cameras with built in analytics that would alarm to intrusions and subjects on the properties along with access control measures. This alternative was selected because of lower ongoing O&M costs and enhanced detection abilities.

Q. What were the total projected capital expenditures for the Critical Substation Upgrade project in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the Critical Substation Upgrade project are in the table provided below.

Critical Substation Upgrade			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 Reference**
2026 Projected			
Software	$0	$0	A-20 (SHB-5), line 242, column m
Material	$312,500	$312,500	A-20 (SHB-5), line 242, column n
Labor	$500,000	$500,000	A-20 (SHB-5), line 242, column o
Contractor	$1,562,500	$1,562,500	A-20 (SHB-5), line 242, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 242, column q
Non-Labor Other	$580,500	$580,500	A-20 (SHB-5), line 242, column r

Total 2026 Projected	**$2,955,500**	**$2,955,500**	A-20 (SHB-5), line 242, column l
2027 Projected			
Software	$0	$0	A-20 (SHB-5), line 320, column m
Material	$312,500	$312,500	A-20 (SHB-5), line 320, column n
Labor	$1,000,000	$1,000,000	A-20 (SHB-5), line 320, column o
Contractor	$2,562,500	$2,562,500	A-20 (SHB-5), line 320, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 320, column q
Non-Labor Other	$708,500	$708,500	A-20 (SHB-5), line 320, column r
Total 2027 Projected	**$4,583,500**	**$4,583,500**	A-20 (SHB-5), line 320, column l
2028 Projected			
Software	$0	$0	
Material	$312,500	$312,500	
Labor	$1,000,000	$1,000,000	
Contractor	$2,562,500	$2,562,500	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$708,500	$708,500	
Total 2028 Projected	**$4,583,500**	**$4,583,500**	
Total Projected			
Software	$0	$0	
Material	$937,500	$937,500	
Labor	$2,500,000	$2,500,000	
Contractor	$6,687,500	$6,687,500	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$1,997,500	$1,997,500	
Total Projected	**$12,122,500**	**$12,122,500**	

Q. What are the current projected total project costs broken down by year for the Critical Substation Upgrade project?

A. The total project costs broken down by year for the Critical Substation Upgrade project are in the table provided below.

Critical Substation Upgrade			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-22070 Reference**
2026 Projected			
Software	$0	$0	A-20 (SHB-5), line 168, column m
Material	$312,500	$312,500	A-20 (SHB-5), line 168, column n
Labor	$609,375	$609,375	A-20 (SHB-5), line 168, column o
Contractor	$1,562,500	$1,562,500	A-20 (SHB-5), line 168, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 168, column q
Non-Labor Other	$116,520	$116,520	A-20 (SHB-5), line 168, column r
Total 2026 Projected	**$2,600,895**	**$2,600,895**	A-20 (SHB-5), line 168, column l
2027 Projected			
Software	$0	$0	A-20 (SHB-5), line 231, column m
Material	$2,312,500	$2,312,500	A-20 (SHB-5), line 231, column n
Labor	$1,070,000	$1,070,000	A-20 (SHB-5), line 231, column o
Contractor	$562,500	$562,500	A-20 (SHB-5), line 231, column p
Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 231, column q
Non-Labor Other	$640,250	$640,250	A-20 (SHB-5), line 231, column r
Total 2027 Projected	**$4,585,250**	**$4,585,250**	A-20 (SHB-5), line 231, column l
2028 Projected			
Software	$0	$0	A-20 (SHB-5), line 299, column m
Material	$2,312,500	$2,312,500	A-20 (SHB-5), line 299, column n
Labor	$1,070,000	$1,070,000	A-20 (SHB-5), line 299, column o
Contractor	$562,500	$562,500	A-20 (SHB-5), line 299, column p

Non-Labor Overhead	$0	$0	A-20 (SHB-5), line 299, column q
Non-Labor Other	$640,250	$640,250	A-20 (SHB-5), line 299, column r
Total 2028 Projected	**$4,585,250**	**$4,585,250**	A-20 (SHB-5), line 299, column l
Total Projected			
Software	$0	$0	
Material	$4,937,500	$4,937,500	
Labor	$2,749,375	$2,749,375	
Contractor	$2,687,500	$2,687,500	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$1,397,020	$1,397,020	
Total Projected	**$11,771,395**	**$11,771,395**	

Q. Why have the projected costs of the Critical Substation Upgrade project changed from previous projections in Case No. U-21870?

A. The projected total Company and electric allocation for the Critical Substation Upgrade project decreased by $0.35 million in capital expenditures from the projections provided in Case No. U-21870 due to revisions for several cost categories. Contractor costs decreased by $4 million, while material costs increased by $4 million, offsetting one another due to inadvertently assigning the incorrect cost category to the materials. Additionally, it was determined that the IT administration allocation was miscalculated, which increased labor costs by $0.25 million, and non-labor other costs decreased by $0.60 million due to revisions to associated overheads with correcting the cost category for materials.

- The **Forward Web Proxy Services** project requires $1,977,499 ($1,581,999 ROM Adjusted Capital) in capital and $205,053 in O&M in the test year.
    - **Description:** This project will replace the Company's existing web proxy service platform with a new, modern, and more resilient platform designed to support both secure internet access and advanced data loss prevention capabilities. A web proxy service acts as a secure intermediary between users and the internet, evaluating, filtering, and forwarding traffic while enforcing company security policies. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination

web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

- **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; (4) and implementing data loss prevention for web proxy services. The Security team did extensive research on alternative web proxy services solutions.

- **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 wasn't chosen because the capabilities of firewalls aren't as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) Perform an evaluation between existing product with expanded feature sets, such as data loss prevention and alternative vendors that could replace current system with modern vendor platform for web proxy

services. This option was chosen because it offers additional analysis with the potential to enhance existing, in place, products with features such as enhanced data loss prevention mechanisms, browser isolation (the ability to contain web pages so that the web page can't affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.

- The **Privileged Access Management ("PAM") Cloud Migration** project requires $1,064,118 in capital ($851,295 ROM Adjusted Capital) and $147,315 in O&M in the test year.
  - **Description:** This project will perform the implementation of a PAM solution to enhance security by securely storing, rotating, and isolating privileged credentials for both human and non-human users. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure.
  - **Problem Statement:** The Company faces significant security risks related to the management of privileged access, including potential data breaches, unauthorized access, and compliance issues. The Company's current methods of managing privileged accounts are often manual, error-prone, and insufficient to address the complexities of modern IT environments. There is a critical need for a robust solution that can automate and secure the management of privileged credentials, provide comprehensive monitoring and control, and ensure compliance with security policies across on-premises, cloud, and hybrid environments.
  - **Objectives:** This project creates value for the Company through: (1) securely storing and managing privileged credentials; (2) automating credential rotation; (3) isolating access to prevent unauthorized use; (4) improving compliance with regulatory requirements through comprehensive audit trails, and reporting; (5) increasing efficiency by automating password management; and (6) reducing manual tasks that can be prone to human error.
  - **Scope:** The project scope includes migrating the Company's current system PAM system to a cloud vendor, implementing new features not available in the current on-premises solution.
  - **Alternatives:** Alternatives considered included: (1) manual password rotation. This alternative was not chosen because it requires significant time and effort to manage and update passwords manually. It also increases the

risk of human error including mistakes, such as forgetting to update passwords or using predictable patterns; (2) Access Control Lists ("ACLs"). This alternative was not chosen because of scalability issues. ACLs are difficult to manage as the number of users and resources grows. This option also requires regular updates and reviews to ensure accuracy and security; (3) manual audit logs. This alternative was not chosen because it is very labor intensive. It requires significant effort to maintain and review logs manually. The use of manual audit logs increases the risk of inaccuracy by having a higher chance of errors and incomplete records; (4) periodic security reviews. This alternative was not chosen because it is very resource intensive and requires time and expertise to conduct thorough reviews. Periodic security reviews may also miss issues that arise between review periods; and (5) implementation of a cloud based PAM solution was the chosen option. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure.

- The **Vulnerability and Exposure Management Program Enablement** project requires $626,630 ($501,304 ROM Adjusted Capital) in capital and $122,136 in O&M in the test year.
    - **Description:** This project will enhance the Company's Vulnerability Management program by implementing a cohesive suite of technologies focused on Vulnerability Management. These technologies will include minimally the following capabilities: vulnerability management, web application static and dynamic analysis, and attack surface management. Vulnerability Management is a critical process for identifying, assessing, and mitigating security weaknesses within an organization's IT infrastructure. This proactive approach involves continuous monitoring and evaluation of systems to detect vulnerabilities that could be exploited by cyber threats. By prioritizing vulnerabilities based on risk, cost, and potential impact, organizations can effectively allocate resources to address the most critical issues first. Implementing a robust Vulnerability Management program not only enhances the security posture of the organization but also ensures compliance with industry regulations and standards, thereby reducing the risk of data breaches, malware infections, ransomware, and other cyber threats. This Vulnerability Management program supports business continuity and protects sensitive information and systems, making it an essential component of any comprehensive cybersecurity strategy.
    - **Problem Statement:** The Company's current Vulnerability Management program relies on multiple disparate tools to perform core activities such as

scanning, analysis, and remediation tracking. This multi-tool approach can create inefficiencies, increase the likelihood of data gaps, and require additional effort from users to correlate and interpret information across platforms. The use of several systems to manage vulnerabilities can lead to inconsistent workflows, duplicated efforts, and reduced coordination between teams. Streamlining the tool set or improving integration between existing solutions would enhance operational efficiency and support a more cohesive vulnerability management process.

- **Objectives:** This project creates value for the Company by: (1) enhancing the efficiency and effectiveness of the Vulnerability Management program through improved integration and reduced reliance on multiple standalone tools; and (2) supporting risk-based decision-making by enabling more consistent identification, prioritization, and remediation of vulnerabilities. These improvements will reduce operational overhead, minimize security exposure, and help ensure continued alignment with industry regulations and cybersecurity frameworks.
- **Scope:** The project scope includes evaluating and implementing a new vulnerability solution. The scope also includes enablement of active scanning with the new solution, consolidating data sources, and improving cross-platform visibility.
- **Alternatives:** Alternatives considered include: (1) continuing with the current multi-tool Vulnerability Management program. This option was not selected as it perpetuates inefficiencies, inconsistent workflows, and limited visibility across platforms; (2) increasing manual efforts to correlate and manage data between existing tools. This alternative was not chosen due to the high resource demands and increased risk of human error, which may further delay remediation timelines; and (3) procurement of a new, cloud-based consolidated vulnerability management platform. This option was chosen as it allows the Company to enhance vulnerability data, threat intelligence, and process efficiencies within the current environment to deliver immediate value with high confidence in the vulnerability data that is being provided.

- The **Workstation Temporary Administrative Access** project requires $439,407 in capital ($351,526 ROM Adjusted Capital) and $8,988 in O&M in the test year.
  - **Description:** This project will implement controls that allow local temporary administrative access to workstations.
  - **Problem Statement:** Cyber Security and IT teams do not have controls in place to restrict the usage of local administrative accounts or monitoring capabilities to detect misuse without human intervention. The current state

creates an environment for misuse where broad administrative access could be leveraged for data breaches and ransomware. A successful attack would impact the Company's ability to serve our customers.

- **Objectives:** This project creates value for the Company by: (1) reducing risk by eliminating over 1,000 local administrative accounts; (2) adding the ability to implement security controls and restrictions on local administrative functions; (3) increasing productivity by reducing the time and resources needed to provision, manage, and audit local accounts for security compliance; (4) adding the ability to provide administrative access for a specific and limited duration of time, thereby reducing cyber security risk of workstation compromise.
- **Scope:** This project will implement a platform that can enforce security controls and audit the security compliance of local administrative accounts for Company workstations. The features of this platform include: (1) the ability to give administrator access for a specific duration of time; (2) enable applications to automatically run in a privileged state; (3) the ability to remotely change the administrator password; and (4) generate a single-use administrator password.
- **Alternatives:** Alternatives considered include: (1) accepting the risk of using local accounts that are not managed centrally for end point administration. This alternative was not chosen because the usage of these accounts doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (2) continuing the existing practice of manual oversight to grant local administrative access which does not eliminate the risk of misuse of administrator access. This alternative was not selected because it doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (3) developing a platform for administrative account access internally. This alternative was not chosen due to the time frame it would take internal resources to develop and maintain the solution at the same level of quality and feature parity as a commercial product; and (4) implement a cloud platform specifically developed for managing local administrative accounts. This option was chosen because of the features designed for managing local administrative accounts will reduce the risk of misuse of administrative credentials within the Company.

Q. Are there any Security projects that you would like to discuss further?

A. Yes. The following Security projects are addressed below.

- Saviynt EIGA Implementation; and

- Critical Substation Upgrade.

Q. Please explain the Saviynt EIGA Implementation project.

A. The Saviynt EIGA Implementation project requires no capital expenditures and O&M expenses for the projected test year and has the following synopsis:

- **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.

- **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 EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.

- **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; and (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.

Q. What were the total projected capital expenditures for the EIGA Implementation in Case No. U-21870?

A. The Case No. U-21870 projected capital expenditures by year and cost category for the Saviynt EIGA Implementation project are in the table provided below.

Saviynt EIGA Implementation			
Case No. U-21870			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870 Reference**
2024 Actuals			
Software	$1,919,197	$1,336,721	U-21870, A-20 (SHB-5), line 95, column m
Material	$0	$0	U-21870, A-20 (SHB-5), line 95, column n
Labor	$361,658	$251,895	U-21870, A-20 (SHB-5), line 95, column o
Contractor	$334,839	$233,215	U-21870, A-20 (SHB-5), line 95, column p
Non-Labor Overhead	$0	$0	U-21870, A-20 (SHB-5), line 95, column q
Non-Labor Other	$178,867	$124,581	U-21870, A-20 (SHB-5), line 95, column r
Total 2024 Projected	**$2,794,561**	**$1,946,412**	U-21870, A-20 (SHB-5), line 95, column l

2025 Projected			
Software	$0	$0	U-21870, A-20 (SHB-5), line 177, column m
Material	$100,000	$68,570	U-21870, A-20 (SHB-5), line 177, column n
Labor	$308,000	$211,196	U-21870, A-20 (SHB-5), line 177, column o
Contractor	$1,100,000	$754,270	U-21870, A-20 (SHB-5), line 177, column p
Non-Labor Overhead	$138,460	$94,942	U-21870, A-20 (SHB-5), line 177, column q
Non-Labor Other	$253,896	$174,096	U-21870, A-20 (SHB-5), line 177, column r
Total 2025 Projected	**$1,900,356**	**$1,303,074**	U-21870, A-20 (SHB-5), line 177, column l
2026 Projected			
Software	$0	$0	U-21870, A-20 (SHB-5), line 254, column m
Material	$50,000	$34,285	U-21870, A-20 (SHB-5), line 254, column n
Labor	$141,200	$96,821	U-21870, A-20 (SHB-5), line 254, column o
Contractor	$600,000	$411,420	U-21870, A-20 (SHB-5), line 254, column p
Non-Labor Overhead	$0	$0	U-21870, A-20 (SHB-5), line 254, column q
Non-Labor Other	$155,318	$106,502	U-21870, A-20 (SHB-5), line 254, column r
Total 2026 Projected	**$946,518**	**$649,027**	U-21870, A-20 (SHB-5), line 254, column l
Total Projected			
Software	$1,919,197	$1,336,721	
Material	$150,000	$102,855	
Labor	$810,858	$559,912	
Contractor	$2,034,839	$1,398,905	
Non-Labor Overhead	$138,460	$94,942	
Non-Labor Other	$588,081	$405,179	
Total Projected	**$5,641,435**	**$3,898,513**	

Q. What are the current projected total project costs broken down by year for the Saviynt EIGA Implementation project?

A. The total project costs broken down by year for the EIGA Implementation project are in the table provided below.

Saviynt EIGA Implementation			
Case No. U-22070			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**U-21870/-U-22070 Reference**
2024 Actuals			
Software	$1,919,197	$1,336,721	U-21870, A-20 (SHB-5), line 95, column m
Material	$0	$0	U-21870, A-20 (SHB-5), line 95, column n
Labor	$361,658	$251,895	U-21870, A-20 (SHB-5), line 95, column o
Contractor	$334,839	$233,215	U-21870, A-20 (SHB-5), line 95, column p
Non-Labor Overhead	$0	$0	U-21870, A-20 (SHB-5), line 95, column q
Non-Labor Other	$178,867	$124,581	U-21870, A-20 (SHB-5), line 95, column r
Total 2024 Actuals	**$2,794,561**	**$1,946,412**	U-21870, A-20 (SHB-5), line 95, column l
2025 Actuals			
Software	($7,817)	($5,360)	U-22070, A-20 (SHB-5), line 95, column m
Material	$0	$0	U-22070, A-20 (SHB-5), line 95, column n
Labor	$475,947	$326,357	U-22070, A-20 (SHB-5), line 95, column o
Contractor	$1,330,045	$912,012	U-22070, A-20 (SHB-5), line 95, column p
Non-Labor Overhead	$0	$0	U-22070, A-20 (SHB-5), line 95, column q
Non-Labor Other	$186,133	$127,632	U-22070, A-20 (SHB-5), line 95, column r
Total 2025 Actuals	**$1,984,308**	**$1,360,640**	U-22070, A-20 (SHB-5), line 95, column l

2026 Projected			
Software	$0	$0	U-22070 A-20 (SHB-5), line 174, column m
Material	$50,000	$33,120	U-22070 A-20 (SHB-5), line 174, column n
Labor	$239,851	$158,877	U-22070 A-20 (SHB-5), line 174, column o
Contractor	$600,000	$397,440	U-22070 A-20 (SHB-5), line 174, column p
Non-Labor Overhead	$0	$0	U-22070 A-20 (SHB-5), line 174, column q
Non-Labor Other	$383,862	$254,270	U-22070 A-20 (SHB-5), line 174, column r
Total 2026 Projected	**$1,273,713**	**$843,707**	U-22070 A-20 (SHB-5), line 174, column l
Total Projected			
Software	$1,919,197	$1,336,721	
Material	$50,000	$33,120	
Labor	$1,077,456	$737,129	
Contractor	$2,264,884	$1,542,667	
Non-Labor Overhead	$0	$0	
Non-Labor Other	$748,862	$506,483	
Total Projected	**$6,052,582**	**$4,150,759**	

Q. Why have the projected costs of the Saviynt EIGA Implementation project changed from previous projections in Case No. U-21870?

A. The reasons for the $0.25 million electric allocation increase in the Saviynt EIGA Implementation project capital costs from the projections presented in Case No. U-21870 are due to increases in labor ($0.18 million), contractor costs ($0.14 million), and non-labor other ($0.10 million), offset by decreases in non-labor overhead ($0.09 million) and material ($0.07 million). The primary reason for the $0.25 million capital increase is due to the complexity of implementing an enterprise-wide identity governance solution required additional contractor and labor resources. Implementation plans were delayed and a need arose for more technical expertise. The team also had to adjust for inflight platform upgrades of the current EIGA implementation. The labor costs increased by $0.18 million

due to implementation delays and the need to complete additional test cycles given platform version updates. Contractor costs increased by $0.14 million due to challenges on the project that resulted in staffing additional contracted resources. Material costs decreased by $0.07 million due to the server and software license costs being less than planned.

Q. Overall, are the expenses and expenditures you have identified reasonable and prudent?

A. Yes. The O&M expenses and capital expenditures requested in this case will help the Company achieve the outcomes of the IRP and EDIIP, continually improve customers' interactions with the Company, and maintain a reliable and secure technology base that is exposed to ever-increasing and serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures and operational O&M requirements.

I have also provided a detailed synopsis of each project, a supplementary exhibit of the total project cost, hard savings, and cost/benefit analysis for each project in the test year, and a deep dive into benefits for several high-priority projects. This project-specific information demonstrates how IT investments and operational expenses are helping the Company provide exceptional service to its customers. The Company is seeking full recovery for these IT costs that keep its systems available, customers safe from growing cyber security threats, and the Company on a path to the bright future it envisioned in its IRP and EDIIP – one powered by safe, reliable, affordable, clean, and equitable energy.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Senior Executive Director of Financial Planning and Analysis.

Q. What are your current responsibilities?

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model.

Q. Please describe your educational background and describe any positions held prior to your current position.

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but

were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford Motor Company to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I began leading the Company's Financial Planning and Analysis team in February 2016 and I am presently the Senior Executive Director of Financial Planning and Analysis.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 Application to Amend the RE Plan;
- Case No. U-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-17301, the Company's 2013 Application for biennial review of the RE Plan;
- Case No. U-17752, the Company's 2015 Application to Amend the RE Plan;
- Case No. U-17792, the Company's 2015 Application for biennial review of the RE Plan;
- Case No. U-18231, the Company's 2017 Application for biennial review of the RE Plan;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's RE Plan reconciliation proceeding for 2018;
- Case No. U-20650, the Company's 2019 Gas Rate Case;

- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's RE Plan reconciliation proceeding for 2023;
- Case No. U-21585, the Company's 2024 Electric Rate Case;
- Case No. U-21816, the Company's RE Plan amendment proceeding for 2024;
- Case No. U-21806, the Company's 2024 Gas Rate Case;
- Case No. U-21829, the Company's RE Plan reconciliation proceeding for 2024;
- Case No. U-21870, the Company's 2025 Electric Rate Case;
- Case No. U-21979, the Company's ex parte application for Accounting Approval to accrue an Allowance for Funds Used During Construction on construction work in progress for projects within its RE Plan; and
- Case No. U-21981, the Company's 2025 Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy. I will also present my recommendation of the appropriate test year working capital cash balance. Finally, I perform an evaluation of securitization as a cost recovery method for the Company's deferred storm costs.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SUMMARY OF RECOMMENDATIONS

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

1. Explanation of Capital Structure and Test Year Adjustments

2. Rationale for a 51.75% Equity Ratio

B. Development of Cost Rates

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES

IV. PROJECTED CASH BALANCE

V. EVALUATION OF SECURITIZATION AS A COST RECOVERY MECHANISM FOR DEFERRED STORM COSTS

VI. SUMMARY AND CONCLUSIONS

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;

Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
Exhibit A-32 (MRB-8)		Current and Historical Credit Ratings;
Exhibit A-33 (MRB-9)		Recent Utility Corporate Bond Issuances;
Exhibit A-34 (MRB-10)		Peer Company Commission Authorized Equity Ratios;
Exhibit A-35 (MRB-11)		State Regulatory Evaluations;
Exhibit A-36 (MRB-12)		Cumulative Annual Interest Savings;
Exhibit A-37 (MRB-13)		Peer Company Revolver Capacity Analysis;
Exhibit A-38 (MRB-14)		Moody's March 23, 2026 Credit Report;
Exhibit A-39 (MRB-15)		S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy;
Exhibit A-40 (MRB-16)		UBS May 10, 2023 Report;
Exhibit A-41 (MRB-17)		S&P September 15, 2025 Credit Report;
Exhibit A-42 (MRB-18)		Fitch April 11, 2025 Credit Report;
Exhibit A-43 (MRB-19)		S&P January 14, 2026 Report; and
Exhibit A-44 (MRB-20)		Fitch April 8, 2026 Credit Report.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. SUMMARY OF RECOMMENDATIONS

Q. What capital structure do you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of December 31, 2025, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on April 30, 2028. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 51.75%. This is a 175 basis point increase from the prevailing authorized equity ratio of 50.0%. The need for this increase will be discussed in Section A.2.1. Rationale for a 51.75% Equity Ratio. The equity ratio as a percentage of total capital is 44.62%.

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy?

A. I am assuming an ROE for Consumers Energy of 10.25%. This ROE is recommended by Company witness Ann E. Bulkley and supported in further detail in her direct testimony.

Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?

A. I am recommending an overall rate of return of 6.59% on an after-tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

1. Explanation of Capital Structure and Test Year Adjustments

Q. What is capital structure?

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the Company, this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.

Q. What is long-term debt and short-term debt?

A. Long-term debt consists of loans that have a due date (or maturity) that is more than one year from the date of issuance. For the Company, long-term debt consists exclusively of First Mortgage Bonds. Short-term debt represents borrowings that are short-term in nature (less than one year), and includes borrowings under the Company's credit facilities, including commercial paper and intercompany borrowings. The Company aims to finance its long-term capital (such as plant and property) with long-term debt and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with short-term debt. This financing strategy is explained in more detail later in my direct testimony.

Q. What is common equity and preferred equity?

A. Equity is the net worth (assets minus liabilities) of a company. Common equity increases with net income (retained earnings) and with equity contributions from the Company's parent, CMS Energy. Common equity decreases when the Company makes dividend distributions to CMS Energy. Preferred equity is distinguished from common equity in

that there is a fixed preferred dividend rate on preferred stock. Also, preferred equity has a higher ("preferred") claim to the Company's net assets in the event of insolvency.

Q. Do taxes play a part in the capital structure?

A. Yes. Deferred taxes and ITC represent reported book taxes that, due to special Internal Revenue Service deductions, measurements, or treatments, will not have to be paid until sometime in the future. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure.

Q. How did you develop the long-term debt, preferred stock, common equity, short-term debt, deferred income tax, and ITC balances in the capital structure?

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2025, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending April 30, 2028, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $4.125 billion.

A. I have projected that the 13-month common equity balance for the test year will be $4.125 billion higher than the December 31, 2025 balance. The common equity adjustment of $4.125 billion consists of two components. The first is an adjustment to reflect $393 million in projected retained earnings on a weighted average basis from January 2026 through April 2028. The second is an adjustment of $3.732 billion to reflect the projected equity infusions on a weighted average basis from January 2026 through April 2028.

Q. What are retained earnings?

A. Retained earnings are a company's net income from operations and other business activities retained by the company as additional equity capital. Retained earnings are, thus, a part of stockholders' equity.

Q. Please explain the retained earnings adjustment of $393 million.

A. Since I started with the December 31, 2025 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur on a weighted average basis through April 30, 2028.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2026 through March 2026.

A. For the period of January 2026 through March 2026, I relied on actual changes in regulatory retained earnings.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from April 2026 through the test period ending April 2028.

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $18.783 million per month, or $225.4 million per year, from April 2026 through April 2028.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $225.4 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2025, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2025, was $1.127 billion. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated

an annual retained earnings amount of $225.4 million [$1.127 billion x (1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending April 30, 2028.

Q. What are equity infusions?

A. Equity infusions are cash investments made by CMS Energy into Consumers Energy, thereby increasing the Company's common equity balance.

Q. Why did you make a $3.732 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 51.75% equity ratio for the test period in this case, which I will discuss the importance of in Section 2. below. CMS Energy made equity infusions totaling $920 million in 2025 and plans to make equity infusions totaling $1.355 billion in 2026, $2.300 billion in 2027, and $1.100 billion from January 2028 through April 2028. Accordingly, I reflected this in the equity balance for the test year for this case on a weighted average basis. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending April 30, 2028, is $3.732 billion. When the 13-month average for the equity infusions of $3.732 billion is combined with the 13-month average $393 million retained earnings adjustment, the increase to equity capital is the $4.125 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. Please explain the long-term debt adjustment of $3.001 billion.

A. I have projected that the average debt balance for the test year ending April 30, 2028, will be $3.001 billion higher than the December 31, 2025 balance. This adjustment consists of the following components:

Long-Term Debt (in millions)			Apr. 30, 2028 Test Year
Month	Issuance	Retirement	Impact
May 2026	$775	($115)	$660
Aug. 2026	$960	$0	$960
May. 2027	$950	$0	$877
Aug. 2027	$935	$0	$647
Oct. 2027	$0	($100)	($54)
Dec. 2027	$0	($36)	($14)
Mar. 2028	$0	($425)	($65)
Subtotal			$3,011
Changes in Unamortized Fees			(10)
Total			**$3,001**

The development of the 13-month average long-term debt balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. Please describe the planned debt issuances in May 2026, August 2026, May 2027, and August 2027.

A. Each of these planned debt issuances will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2026 will also be used for the retirement of the Company's $115 million 5.24% bonds which mature in May 2026. The debt planned to be issued in August 2027 will also be used for the retirement of the Company's $100 million 3.68% bonds which mature in October 2027. These planned debt issuances have been determined based on the Company's financing plans after evaluating cash and liquidity requirements for the Company.

Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending April 30, 2028?

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending April 30, 2028. The average amount outstanding on line 65, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. What is your projection regarding the level of short-term debt balance for the test year ending April 30, 2028?

A. I have projected an average short-term debt balance for the test year of $156 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b); Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g); and Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 1.

Q. What are the components of the average short-term debt balance?

A. Revolvers, commercial paper, and intercompany borrowing are short-term financing options available to the Company. Revolvers are revolving lines of credit that allow the Company to borrow and repay as long as the outstanding balances remain within the credit limits, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities. Intercompany borrowing represents short-term borrowings from CMS Energy. Intercompany borrowing is drawn under a promissory note with CMS Energy up to $750 million and carries an interest rate of 1-month Secured Overnight Financing Rate

("SOFR")[1] minus 10 basis points. The Company is the beneficiary of intercompany borrowing to meet short-term liquidity needs when it is available and when it is the most cost-effective alternative. It should be noted that the intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company.

Q. How was the short-term debt balance of $156 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of short-term debt for the test year ending April 30, 2028. I have arrived at these projections after considering the projected total monthly cash flow requirements, planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

Q. Are the projections for short-term debt reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers, its Commercial Paper Program, or its intercompany borrowing agreement?

A. The Company borrows on its short-term financing facilities in order from least expensive to more expensive. The following is the prioritized order in which the Company utilizes its short-term financing facilities:

[1] SOFR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world. SOFR replaced the London Interbank Offered Rate ("LIBOR") in 2023.

		Amount	**Credit Capacity**
1a. 1b.	Commercial Paper Intercompany Borrowing**	$500 million $750 million	$500 million*
2.	MUFG Revolver JPMorgan Revolver	$300 million $1.1 billion	$300 million $600 million*
	Total		$1.40 billion

*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available).

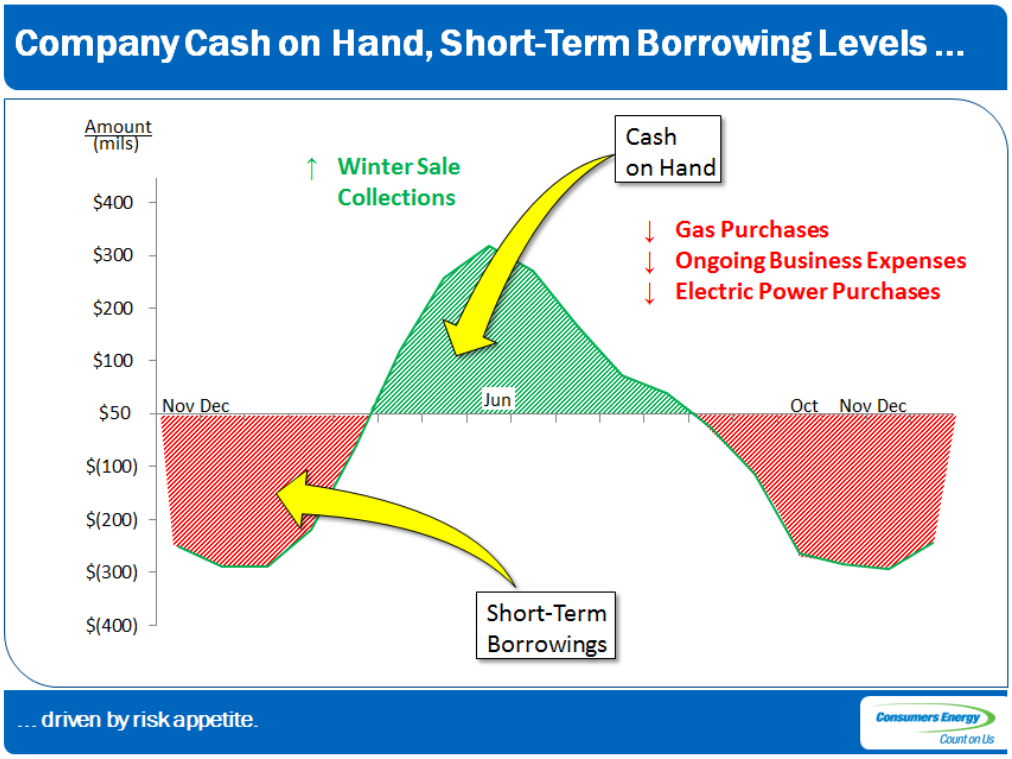
**Intercompany Borrowing or Commercial Paper is used first, depending on availability and which alternative is the most cost-effective at the time of borrowing.

All of the projected test year balances for short-term debt are assumed to be issued under the Company's Commercial Paper Program. This program, along with the intercompany borrowing facility, are the least expensive short-term financing options to the Company and are assumed to be used first when the need arises. The $300 million MUFG revolving credit facility and the remaining $600 million JPMorgan revolver ($1.1 billion total capacity less $500 million drawn commercial paper) are the next least-costly, short-term financing options.

Q. How does the timing and amount of short-term borrowings fit into the Company's overall liquidity and financing strategy?

A. The Company strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities. The timing and amount of short-term borrowings is directly related to the level of cash on hand. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in

the fall and winter months. Throughout the year, however, a minimum level of cash on hand is maintained. This is reflected in the following chart which depicts the typical cash and short-term borrowing levels through a given year:



Q. In order to reduce costs, would the Company consider maintaining a permanent layer of short-term debt?

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil described earlier in my testimony. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends

of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is generally comfortable financing between $200 million and $400 million of this gap with short-term borrowings as doing so leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this should be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the required equity balance would need to increase in order to achieve the 51.75% equity ratio. Doing so would result in a higher overall cost of capital.

Q. How does the Company balance the benefit of carrying sufficient liquidity with the cost of maintaining its short-term credit capacity?

A. The Company's projected $1.40 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects up to $480 million of short-term borrowings, utilizing most of the $500 million capacity of the Commercial Paper Program. Access to the commercial paper market, however,

requires an equivalent amount of revolving credit capacity as a "backstop;" therefore, of the Company's $1.40 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $900 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

Q. Did the dramatic increase in natural gas prices in 2022 serve as an example of the importance of the Company holding sufficient short-term credit capacity?

A. Yes. The Company generally funds its natural gas purchases using short-term borrowing. Surging demand in the United States combined with national inventory levels below historical averages drove gas prices higher in 2022. In addition, Russia's invasion of Ukraine and the related energy market disruptions further increased gas prices. As a result, the Company had to purchase natural gas at significantly higher prices. In fact, the Company held over $1 billion in short-term debt in November and December 2022, as previously described. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is not guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets as described earlier in my direct testimony. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

Q. Are the Company's short-term credit facilities also used in a way other than cash draws or borrowing?

A. Yes. The Company issues letters of credit to cover ongoing operating activities such as fuel purchases or margin support and also to cover Midcontinent Independent System Operator, Inc. ("MISO") margin obligations which are necessary for a utility participating in MISO's energy and transmission markets. The Company's credit facilities provide a necessary and required backstop against these letters of credit. The use of letters of credit is normal and customary for utilities in conducting ongoing business operations. While not considered a cash draw, the Company is utilizing its credit facilities as issued letters of credit which reduce the credit capacity of those facilities.

Q. How does the cost of the Company's short-term credit facilities benefit the Company and its customers?

A. Short-term credit facilities play a critical role in supporting the Company's financial strength and stability. Even when there are no outstanding borrowings, the cost of these facilities provides essential protection against unexpected short-term financing market disruptions as described earlier in my direct testimony. This is no different than an individual bearing the cost of a home, auto, or life insurance policy which may not be utilized for periods of time but are nonetheless customary and necessary to maintain in case of unforeseen events. Thus, the cost of the Company's short-term credit facilities (even with little or no outstanding borrowings) benefits the Company and customers by providing enhanced financial strength and security and supporting business operations.

Q. Does short-term credit capacity impact the Company's credit quality?

A. Yes. The Company's short-term credit capacity, along with cash on hand, is a component of liquidity which is a key factor in rating agencies' assessment of the Company's overall financial health. Based on guidance issued by all three major credit rating agencies, it is apparent that the Company's liquidity (which includes short-term credit capacity) is an important component of their assessment of the Company's credit quality and credit rating.

Q. Do the rating agencies consider the Company's liquidity including short-term credit capacity to be excessive?

A. No. Refer to Exhibit A-41 (MRB-17). In September 2025, S&P assessed the Company's liquidity, including its short-term credit capacity, as "Adequate," noting that their rating reflected the Company's "prudent risk management." Also refer to Moody's March 2026 credit opinion reflected on Exhibit A-38 (MRB-14). In its credit evaluation, Moody's stated "we expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months." Moody's also refers to the Company's amount of external liquidity as "reasonable." Finally, refer to Exhibit A-42 (MRB-18), Fitch's April 2025 credit opinion. In its assessment, Fitch identified the Company's revolving credit facilities as supporting short-term liquidity needs and rated the Company's liquidity as "adequate." It is clear from these reports that the consensus among rating agencies is that the Company's short-term credit capacity is not considered excessive but is rather "adequate" considering the Company's liquidity needs and provides a suitable cushion to protect against times of economic stress and financial market disruption. A greater reliance on the Company's short-term credit facilities would result in a reduction in that credit capacity, leading to a weakening of the Company's liquidity profile and credit quality.

Q. Is the size of the Company's short-term credit facilities in line with that of other utilities?

A. Yes. Refer to Exhibit A-37 (MRB-13). At year-end 2025, peer companies maintained, on average, a ratio of revolving credit facilities to net Property Plant and Equipment of 5.3%. The Company's credit capacity of 4.9% is just below other companies in the utility industry.

Q. Have other utilities been increasing their short-term borrowing capacity?

A. Yes. Refer to Exhibit A-43 (MRB-19). In a January 2026 report on North American regulated utilities, S&P highlights "exploding" capital expenditures over the past decade focused on safety, reliability, and energy transition. S&P reported record capital spending in the industry in 2025. As utilities' capital spending has continued to rise, so too has companies' short-term liquidity needs. Recently, there have been multiple examples of other utilities increasing their short-term borrowing capacity. For example in December 2025, Ameren Corporation increased its short-term borrowing capacity by $600 million from $2.6 billion to $3.2 billion. Also, in April 2025, Dominion Energy increased its short-term borrowing capacity by $1.1 billion from $6.9 billion to $8.0 billion, underscoring its commitment to maintaining a strong financial foundation for its operations and future growth initiatives. Finally, Duke Energy increased its credit facility from $9 billion to $10 billion in March 2025. In its announcement of the credit capacity upsizing, the company noted: "The expansion and extension of the credit facility underscore Duke Energy's commitment to maintaining robust financial health and supporting its operational and strategic initiatives. This development is expected to provide the company with greater liquidity and an extended timeline to leverage financial resources effectively." It is clear

that other utilities are increasing their short-term credit capacity in order to meet growing liquidity needs and enhance financial flexibility. An adequate amount of short-term borrowing capacity will also be critical for Consumers Energy as it executes its capital investment plan to support a more reliable, resilient, and increasingly clean energy system for its customers as outlined by the Company's capital witnesses in this case.

Q. Has the Company included the renewable liability balance in its projected short-term debt balance?

A. No. Consistent with the Company's Renewable Energy Plan in Case No. U-21816 filed in November 2024, a renewable liability balance is not expected through the test year of this case. As described earlier in my direct testimony, the capital structure in general rate cases is composed of financing components used to fund its operations and capital investment and includes debt, equity, and deferred income tax balances. Since it would be inappropriate to include an asset balance, the Company has thus excluded this component from the projected capital structure.

Q. Please explain the deferred income tax adjustment of $388 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending April 30, 2028, will be $388 million higher than the December 31, 2025 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2026 through April 2028. These adjustments total $388 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

Q. How was the ITC balance determined?

A. The Company's Tax Department has projected that the average ITC balance for the test year ending April 30, 2028 will be $150 million, $32 million higher than the December 2025 balance of $118 million. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2026 through April 2028. These adjustments total $32 million on a 13-month average basis for the test year.

Q. What balances did you use for ITC in the proposed capital structure?

A. I allocated the components for ITC based upon the allocation of long-term debt, preferred stock, and common equity in the recommended capital structure.

2. Rationale for a 51.75% Equity Ratio

Q. How is your testimony structured with regard to the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 51.75% is organized as follows:

i. Equity Ratio/ROE Impact on Credit Quality

ii. Rating Agencies' Assessment of Credit Quality

iii. Peer Authorized Equity Ratios are Higher

iv. Rating Agencies' Assessment of the Regulatory Environment

i. Equity Ratio / ROE Impact on Credit Quality

Q. How does the equity ratio approved in this case impact the Company's credit metrics and credit quality?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to

be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration. Given the Company's recent downward trend in credit metrics and Moody's negative credit outlook opinion (discussed below), an equity ratio of 51.75% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that is sufficient in striking this balance.

Q. What is an FFO-to-Debt ratio?

A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a type of payback ratio, reflecting the Company's ability to repay its outstanding debt with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. A higher credit rating, in turn, results in lower financing rates. This is comparable to a bank's credit evaluation for someone requesting a personal loan. After reviewing personal income and outstanding debt, banks generally offer lower financing rates to individuals who have more cash flow to repay debt, indicating a relatively higher credit quality.

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize

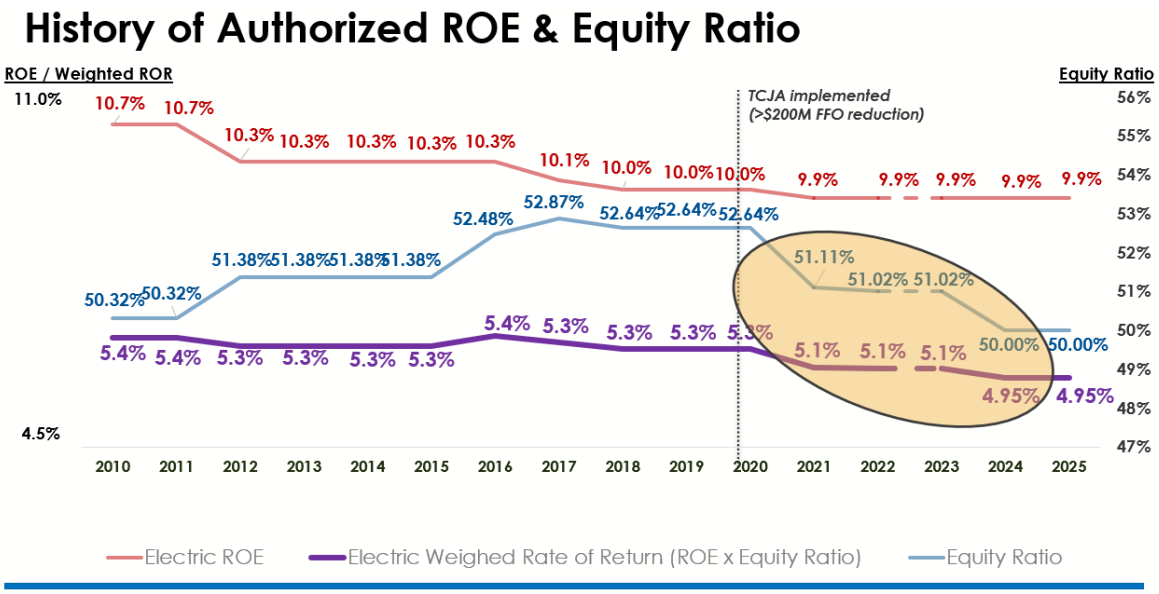
that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. An ROE of 10.25%, when taken together with an equity ratio of 51.75% results in an FFO-to-Debt ratio that the Company believes is acceptable in this instant case and is responsive to recent Commission orders. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health.

Q. How can the combined cost of a Company's equity ratio and ROE components be properly evaluated?

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the equity ratio of 51.75% from column (c) is multiplied by the ROE of 10.25% from column (e) to produce a weighted cost of 5.30%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination with the ROE. As discussed earlier in my testimony, the 51.75% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in this instant case.

Q. What has been the recent trend of the Company's weighted rate of return?

A. Following a long period of stability, recent rate cases have resulted in a sharp decline in rate of return. This is illustrated in the following chart which includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return.



As shown in this graph, the Company's authorized equity ratio has decreased 264 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk.

Q. What has been the trend of the Company's credit metrics over the last few years?

A. The Company's FFO-to-Debt ratio as calculated by Standard and Poor's ("S&P") has been trending down in recent years from 21.7% in 2021 to 17.9% in 2024, a decrease of 380 basis points, indicating a clear weakening of credit strength. Later in this testimony, I also illustrate Moody's downward trajectory, with the Company's credit metrics falling below the level required to maintain its current rating. As the Company's credit metrics deteriorate and move closer to downgrade thresholds, the Company's credit cushion narrows and the risk of a downgrade increases, which is something that has already occurred in Moody's case. In light of the recent credit metric degradation, the ROE and equity ratio proposed by the Company in this case are essential to stabilizing the Company's financial profile and protecting against further credit deterioration.

Q. Is the trend in the Company's credit deterioration limited to the last few years?

A. No. The Company's credit metrics have deteriorated significantly compared to the credit metrics held 10 to 15 years ago. The Company's FFO-to-Debt ratio as calculated by Moody's averaged 25.2% between 2014 and 2017 but has fallen to 16.8% today, a decrease of 840 basis points. The downward trajectory reflects a series of significant credit pressures that have weakened the Company's credit profile over this time, including:

- Federal tax reform that significantly reduced cash flow,
- Service restoration costs that have exceeded amounts included in rates,
- A growing reliance on cost deferral mechanisms causing a lag in cash recovery, and
- Significant increases in spending related to renewable energy, asset retirement obligations, and energy waste reduction.

These credit headwinds have been compounded by a significant reduction in the Company's authorized ROE and equity ratio. Since 2016, the authorized ROE has fallen 40 basis points, from 10.30% to 9.90%, and the authorized equity ratio has dropped 248 basis points, from 52.48% to 50.00%. These reductions directly weaken the Company's credit quality. The Commission should recognize that the weakening credit metric trend is not a short-term anomaly, but rather a long running, material erosion of credit strength that must be addressed to ensure the Company's continued financial stability and preserving its existing credit ratings

Q. Are there additional credit metric considerations for the Company through the test year of this case?

A. Yes. The Company has multiple cost deferral mechanisms, both approved and pending in various cases. These deferral mechanisms provide meaningful value for customers by deferring immediate cost recovery and for investors by preserving non-cash earnings

during the deferral period. While the Company is in full support of these expense deferral mechanisms as a method to complete emergent and necessary customer work outside of traditional rate relief, the cash flow and credit metric impact must also be considered as the Company continues to fund more customer investment ahead of customer collections. During the deferral period, the Company must absorb the cash and expense burden to fund the programs while not collecting any of those costs from customers. This has the effect of increasing long-term financing needs for the Company without creating cash flow the way traditional capital does via non-cash depreciation expense in rates. The credit metric pressure resulting from these deferral mechanisms makes the authorized ROE and equity ratio a critical factor in maintaining the Company's good credit quality.

Q. Does the Company's long-term capital plan, including its upcoming Integrated Resource Plan ("IRP") also demonstrate the need for a higher equity ratio in this proceeding?

A. Yes. The Company plans to file an IRP later this year which will include an unprecedented level of investment over several years to deliver long term value to customers by improving reliability, providing sufficient capacity to meet peak customer demand, complying with renewable and clean energy requirements, and addressing customer affordability through a balanced and cost-effective resource strategy. This IRP will include major, multi-year electric supply projects, for which construction will need to commence in the near future. These investments require substantial upfront capital and involve extended periods of regulatory lag, during which the Company must fund construction costs without corresponding cash recovery. To bridge this gap, the Company must rely heavily on external financing. Moody's statement on the drivers of their change to a negative outlook

for Consumers makes clear that they need to see regulatory support for higher equity funding in advance of approval of these projects to avoid being downgraded.

Q. Do extreme weather events also have a negative impact on the Company's credit quality and demonstrate the need for a higher equity ratio in this proceeding?

A. Yes. From late March through early April 2025, the Company's service territory experienced the most severe ice storm in northern Michigan in more than a century, as confirmed by the National Weather Service. The restoration costs from this catastrophic event significantly depressed the Company's cash-flow metrics in 2025 and will continue to do so into 2027 because these costs cannot be considered for recovery until this case. The cash and credit metric effects of this storm therefore extend well beyond a single year. In addition, another major weather event occurred in March 2026, again negatively impacting cash flow and further pressuring the Company's credit metrics. These events illustrate that severe storms are not isolated anomalies but are recurring and increasingly frequent events that materially affect the Company's cash flow, liquidity, and credit quality. Therefore, a stronger equity ratio is necessary to absorb these shocks and avoid a credit downgrade.

ii. Rating Agencies' Assessment of Credit Quality

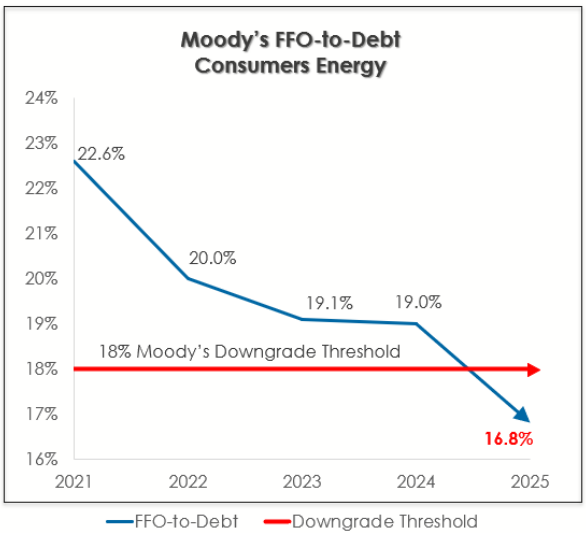
Q. Has any rating agency changed its assessment of the Company's credit outlook?

A. Yes. As shown in Exhibit A-38 (MRB-14), in March 2026, Moody's changed its credit outlook for Consumers Energy from stable to negative. When a rating agency assigns a negative outlook, it is signaling that the company's financial condition (including its credit metrics) is deteriorating to the point where a credit rating downgrade has become a material near-term risk. In its rationale for the outlook change, Moody's emphasized this point, citing the Company's weakened credit metrics and stating that it expects Consumers

Energy's credit metrics to be "sustained below the current threshold for a potential downgrade of 18%."

Q. Does Moody's credit opinion link the Company's equity ratio to its credit quality and credit rating?

A. Yes. Moody's reports that Consumers Energy's credit metrics have fallen below its downgrade threshold and are expected to remain at these levels without stronger equity support. In its report, Moody's states that "the significant step up in the company's capital investment plan without contemporaneous cost recovery through higher equity capital structure and more timely cash recovery mechanisms for large projects, will constrain the company's ability to produce credit metrics that are appropriate for its credit rating" (emphasis added). Moody's also specifically identified the Company's CFO pre-working capital-to-debt ratio for 2025 of 16.8%, which is already below the downgrade threshold. While severe storms contributed to credit metric deterioration in 2025, the Company's credit metrics had already been declining in the years prior. As shown in the following graph, the Company's downward trajectory has continued and now falls below the level required to maintain its current credit rating:



A 51.75% equity ratio and 10.25% ROE is therefore essential to stabilizing credit quality, preventing a credit downgrade, and avoiding higher long-term financing costs that would ultimately be borne by customers.

Q. Does Moody's credit opinion emphasize the importance of the Company's regulatory proceedings (including this case) to the Company's ability to avoid a credit rating downgrade?

A. Yes. Moody's is explicit in its opinion that the outcomes of the Company's pending and near-term regulatory cases will play a key role in its credit assessment. Moody's states that "a constructive outcome on its pending rate case and future regulatory decisions will be important to preserve the company's credit quality and an outlook change back to stable." It is clear that the outcome of this case - including the authorized ROE and equity ratio - will be closely evaluated by Moody's as it assesses whether a credit rating downgrade is warranted. For these reasons, a 51.75% equity ratio is appropriate to sustain the Company's financial integrity and credit strength.

Q. Is the cost of a credit downgrade limited to higher interest rate spreads on future long-term debt issuances?

A. No. The cost of a credit rating downgrade extends far beyond the incremental interest expense on new long-term debt. A downgrade can also increase the cost of existing variable rate debt and raise expenses associated with refinancing transactions. In addition, it can elevate the Company's cost of funding essential day-to-day operations, including utilizing short-term borrowing facilities and issuing required letters of credit. A lower credit rating could also hinder the Company's ability to raise capital during periods of extreme market stress.

Q. Is the Company's risk limited to a one-notch credit downgrade?

A. No. Given the Company's current credit metric trajectory, a one-notch downgrade is likely without supportive regulatory action. However, a two-notch downgrade cannot be ruled out. The impact of a two-notch downgrade could have broader and more serious consequences, including:

- Jeopardizing the Company's access to the commercial paper market (its primary, lowest cost source of short-term liquidity),
- More restrictive or costly terms with essential counterparties such as contractors, PPA operators, and suppliers who may require additional credit support or impose more demanding contract requirements, and
- Stricter conditions imposed by the Company's bank lenders on its debt arrangements such as a lower maximum debt-to-capital ratio.

Q. What would be the FFO-to-Debt ratio threshold for a Moody's two-notch downgrade to A3 and how does that compare to the Company's actual rating in 2025?

A. Based on conversations between the Company's Treasury team and Moody's, the threshold is expected to be 16% though the rating agency does not make that final determination until a new rating is assigned. This is only 80 basis points below the 16.8% ratio the Company experienced in 2025. Given the incremental credit headwinds the Company may be experiencing over the next several years, as described later in my direct testimony, this makes a double downgrade a meaningful risk that must be addressed proactively.

Q. If the Company were to experience any credit downgrade, would the effects be temporary, or would they have long-lasting consequences for customers?

A. A credit downgrade would likely have long-lasting consequences and would be very difficult to reverse. Following such a credit degradation, rating agencies would typically require a long period of sustained credit improvement before considering an upgrade. As described above, during that extended period the Company would face persistently higher

borrowing costs, reduced financial flexibility, and potentially more restrictive terms from lenders, suppliers, and other counterparties. These conditions would create significant long-term customer affordability implications, as the elevated cost of capital would flow through to customers for an extended period of time. However, there is a relatively small but meaningful step the Commission can take now to avoid these long-lasting impacts: adopting a supportive ROE and equity ratio, as proposed by the Company in this case. This action is justified in the near term to stabilize credit quality and shield customers from the far greater and long-lasting costs associated with a credit downgrade.

Q. Do any other credit rating agencies, in addition to Moody's, indicate that the Company's credit metrics have fallen below the downgrade threshold?

A. Yes. Refer to Exhibit A-44 (MRB-20). In April 2026, Fitch issued a credit opinion on the Company and, while not changing its credit outlook, noted the Company's "pressured" credit metrics, including a FFO leverage ratio of 5.0 in 2025 which exceeds the 4.5 ratio that could lead to a credit downgrade. In its credit opinion, Fitch stated that "continued regulatory support is key to the company's ability to deleverage. While not expected currently, restrictive regulatory outcomes, absent other mitigatory actions like credit supportive capital allocation, would keep leverage elevated for longer and could lead to negative rating actions." Like Moody's, Fitch recognizes that the Company's current financial profile does not support its current credit rating. Both rating agencies will closely evaluate the regulatory outcomes in this case, including the authorized ROE and equity ratio, as key factors in their future credit assessments.

Q. What are the customer benefits of the Company maintaining the needed financial cushion to avoid a credit rating downgrade?

A. A higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. As shown in Exhibit A-36 (MRB-12), the Company is saving customers $89 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits extend far beyond this long-term rate stability. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments in core infrastructure assets and modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf.

Q. Are there other customer benefits of the Company maintaining a higher credit rating?

A. Yes. The common equity balance and equity ratio projected for the test year in this case strengthens the Company's credit profile to better withstand any shocks in the financial markets. An example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by

the ensuing market panic. Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital markets which serve as a key source of financing for the Company's investments on behalf of customers. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates.

iii. Peer Authorized Equity Ratios are Higher

Q. How does the 51.75% equity ratio proposed in this case compare to other utilities?

A. To compare the 51.75% equity ratio proposed in this case to other utilities, I researched all rate case decisions of peer companies from 2021 through mid-April 2026 and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-34 (MRB-10). Peer companies for this analysis are defined as regulated subsidiaries of the Company's ROE proxy group reflected on Exhibit A-14 (AEB-1), Schedule D-5, page 2, and excludes orders received by in-state proxy DTE Energy Company as well as the Company. The average equity ratio for the peer group was 52.06%, 31 basis points higher than the 51.75% proposed for Consumers Energy in this case.

Q. Are the equity ratios reflected in your sample based on reported financial data or Commission-authorized equity ratios in regulatory proceedings?

A. The equity ratios were taken from Commission orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the

Company's peer group are granting equity ratios that are higher than the 51.75% that is proposed by the Company in this instant case.

Q. Are the utilities included in Exhibit A-34 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?

A. The utilities included in Exhibit A-34 (MRB-10) are at the regulated subsidiary level. This is important because Consumers Energy is a regulated subsidiary; therefore, the comparison to the average commission-authorized equity ratios also needs to be at that same level in order for the analysis to be a valid comparable benchmark in this case.

Q. Is it appropriate to use equity ratios at the parent holding company level in order to determine the average "peer group" equity ratio for the Company in this case?

A. No. Companies at the parent holding company level should not be considered "peers" for purposes of determining the average equity ratio for the Company's peer group. This would be a misleading comparison since equity ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, an analysis of equity ratios at the parent holding company level may also be skewed since the source for this data is most likely Securities and Exchange Commission reported financial statements, which are prepared under Generally Accepted Accounting Principles. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis which would further distort the equity ratios calculated at the parent holding company level.

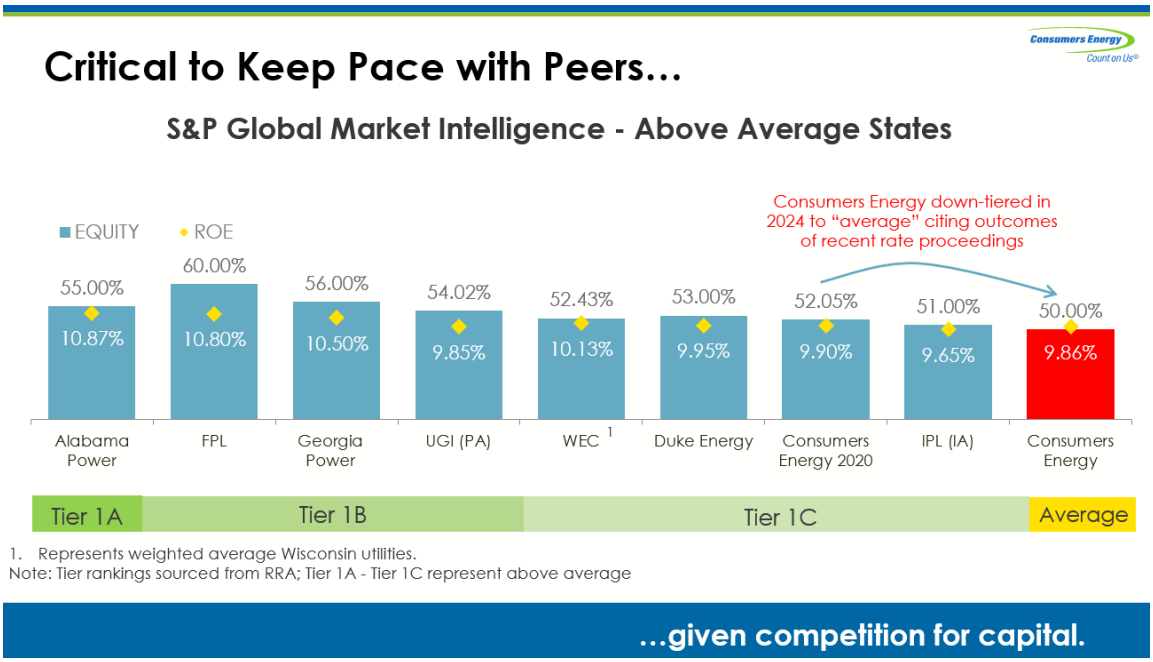
Q. Has the Commission addressed the fact that an analysis of equity ratios at the parent holding company level is not appropriate?

A. Yes. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." It is clear from the Commission's Order that actual Commission-authorized equity ratios at the regulated subsidiary level as presented in Exhibit A-34 (MRB-10) are the preferred data source for an analysis comparing relative equity ratios of peers.

iv. Rating Agencies' Assessment of the Regulatory Environment

Q. How else does the equity ratio and ROE impact the Company's credit quality?

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. Refer to Exhibit A-39 (MRB-15), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." This is reflected in the following chart:



In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." In recent rate case filings, the Company has included this chart, noting that the recent decline in the Company's weighted rate of return has led to the risk that the Company will no longer be ranked as a utility in an above-average tier jurisdiction. S&P's August 2024 report confirms that this risk has been realized.

Q. Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded Michigan from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs ranking in the 3rd quintile as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-40 (MRB-16). It is

apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's above average regulatory standing needs to be protected and bolstered rather than leveraged to justify further credit deterioration and over-leveraging of the Company.

B. Development of Cost Rates

Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) by column (e). The pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g) by the conversion factors in column (h).

i. Long-Term Debt Cost Rate

Q. What long-term debt annual cost rate did you use in this case?

A. I developed a 4.72% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances

outstanding as of December 31, 2025. I then added the planned new debt issuances in May 2026, August 2026, May 2027, and August 2027. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 45 through 48.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2026, August 2026, May 2027, and August 2027.

A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate. For each of these planned debt issuances, I then added a 134 basis point credit spread. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

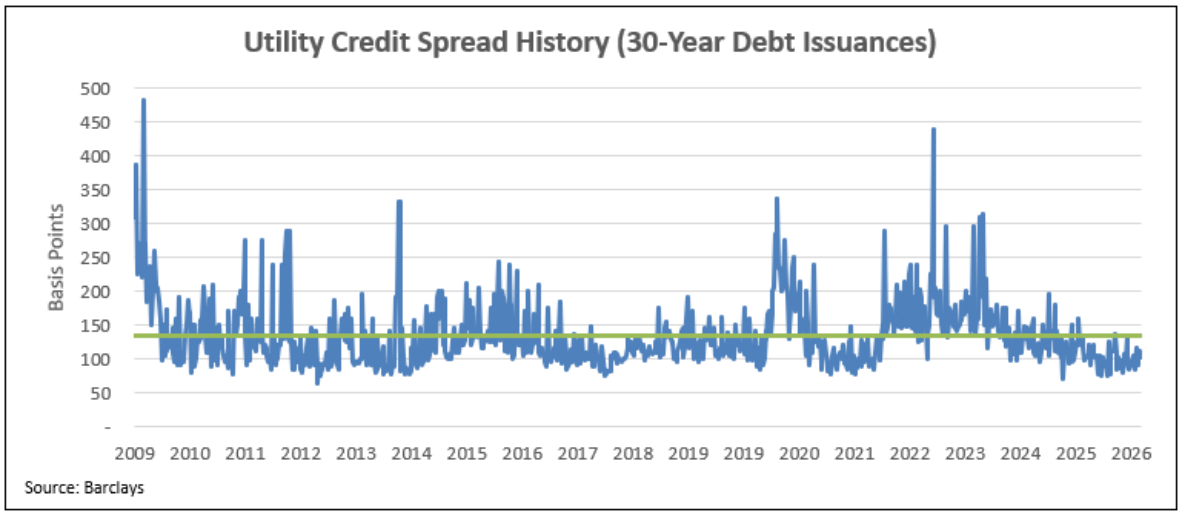
Q. What is a credit spread?

A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

Q. How did you calculate the credit spread of 134 basis points?

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit

rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. In addition, credit spreads can be quite volatile in short periods of time. The volatility of credit spreads is illustrated on the following chart:



Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 17 years. From 2009 to mid-March 2026, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 134 basis points. This credit spread is very reasonable in relation to the historical spreads for 30-year debt issuances, as evidenced in the chart above.

Q. Are there any existing long-term debt issuances that have variable interest rates?

A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances shown on line 27 and lines 30 through 31 have variable interest rates.

Q. What cost rates did you use for these variable rate issuances?

A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 4 basis points. Therefore, I took the projected three-month SOFR for the test year in this case (equal to 3.42%) and subtracted 4 basis points for an interest rate of 3.38%.

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 59.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 59, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 59?

A. The amount shown on line 59 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending April 2028 is $4,416,000.

ii. <u>Short-Term Debt Cost Rate</u>

Q. What short-term debt cost rate did you use in this case?

A. I used a short-term debt cost rate of 4.94%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

Q. Please explain the cost of short-term debt.

A. I projected a cost of short-term debt of $7.7 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **Interest on Borrowings** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $156.0 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1- to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected SOFR rate for the test year of 3.42%. This was multiplied by the projected balance of $156.0 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $5.3 million for borrowings under the Commercial Paper Program;

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertain to normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support and also Letters of Credit to cover MISO margin obligations;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the MUFG revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $1.0 million for commitment fees; and

4. **Amortization/Expense of Facility Fees** – At the inception of a revolving credit facility as well as periodic renewals and extensions, the borrower is required to pay upfront fees to the lenders. These issuance and upfront costs are amortized over the life of the revolver. For the Commercial Paper Program, there are annual fees required to maintain the facility. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for amortization of upfront revolver fees.

Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?

A. These fees and costs are customary in revolving credit facilities and commercial paper agreements and are necessary to secure the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities, which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they need to be recovered as part of long-term debt cost. Refer to my earlier direct testimony which explains and justifies the cost of the Company's short-term borrowing facilities. The cost of short-term debt – short-term credit facilities represent the cost to provide $1.40 billion of necessary liquidity to Consumers Energy.

iii. Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

iv. Common Equity Cost Rate

Q. What rate did you use for the cost of common equity?

A. Based on my recommended equity ratio of 51.75%, I applied a cost rate of 10.25% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the

Commission should adopt with that principle in mind in order to preserve Consumers Energy's current credit rating.

v. Other Cost Rates

Q. What cost rates did you use for the remaining components of the capital structure?

A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero cost. The cost rates for each of the three components of ITC correspond to the cost rates for long-term debt, preferred stock, and common equity.

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS, AND RECENT UTILITY BOND ISSUANCES

Q. Please describe Exhibit A-32 (MRB-8).

A. Exhibit A-32 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-32 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings, Inc. ("Fitch"). The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

Q. Please describe Exhibit A-33 (MRB-9).

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-33 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to and three months subsequent to, each of Consumers Energy's

long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

IV. PROJECTED CASH BALANCE

Q. Should the projected cash balance for the test year ending April 30, 2028 be based on the average cash balance for the 13 months ended December 31, 2025 (the working capital historical period)?

A. No. Using the 13-month working capital historical period average produces a cash balance of $142.6 million, which is higher than what would normally be expected or required for the Company in the test year of this case.

Q. In several previous rate case filings, you supported a projected cash balance equating to approximately 1% of test year revenues. Is the Company using that approach in this case?

A. No. In its March 2026 Order in Case No. U-21870, the Company's most recent electric rate case prior to this case, the Commission indicated a preference for using a historical average cash balance when projecting working capital cash. While the Company continues to view its long-standing 1% of revenues method as reasonable and well supported, it is responding to the Commission's updated guidance. Consistent with that direction, the Company is now proposing to base the test year cash balance on a five-year historical average, which results in a projected cash balance of $56.6 million.

Q. Do you believe that a five-year average is preferable to using a shorter averaging period?

A. Yes. A five-year average more effectively smooths out fluctuations and limits the effect of unusual events. A longer timeframe better reflects normal cash flow variation, minimizes the impact of short-term anomalies, and provides a more reliable indication of the Company's typical cash requirements. The 13-month working capital historical period average of $142.6 million illustrates this point clearly, as it is far higher than what would reasonably be expected or required for the Company. As a result, the five-year historical average of $56.6 million is a more stable and representative measure of the Company's typical cash position.

Q. Does the Company's projected cash balance for the test year of $56.6 million reduce liquidity risk?

A. Yes. Having adequate cash on hand reduces the Company's reliance on short-term borrowing facilities for long periods of time. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. As described earlier in my testimony, the Company does not pursue a strategy that maintains a permanent balance of short-term debt, however, the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's projected cash balance for the test year in this case is reflective of normal levels of cash that are expected and necessary for the Company to manage working capital requirements and manage financial risk.

Q. In addition to managing financial risk, what are some benefits associated with the Company maintaining a sufficient cash balance as projected by the Company?

A. In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity. Having adequate levels of cash on hand allows the Company additional flexibility in securing the lowest interest rate on its long-term debt issuances, which benefits the Company and customers. In addition, given the Company's large capital expenditure program, the Company aims to maintain an overall liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets. For these reasons, the Company's projected cash balance included in working capital for the test year in this case is reasonable and is supportive of the Company's operating, investing, and financing activities.

Q. Does the Company's cash balance impact its credit rating and credit quality?

A. Yes. For example, S&P uses a quantitative measure in assessing liquidity in its evaluation of the Company's credit quality. With this measure, S&P looks at cash on hand and projected cash sources and uses in determining the Company's "liquidity cushion." In its ratings methodology document, S&P describes liquidity as "an important component of our financial risk assessment across the entire rating spectrum… In our view, unlike most other rating factors that we blend together in assessing an issuer's risk profile, a lack of liquidity could precipitate the default of an otherwise healthy entity." Another rating agency, Moody's, has commented on liquidity as saying, "we consider liquidity a key element of our analysis of regulated electric and gas utilities." In assessing the Company's

credit quality, Moody's performs a similar analysis of the Company's liquidity cushion and flexibility as S&P, estimating the Company's ability to meet near-term anticipated cash requirements using its available sources. The third major credit rating agency, Fitch, also has a liquidity measure which is calculated as the amount of readily available cash and credit capacity to service or meet debt maturities and interest obligations. This score indicates if the Company has adequate headroom with cash on hand to cover its operating and short-term liquidity requirements. It is apparent that all three major credit rating agencies consider the level of cash on hand to be an important component of their assessment of the Company's credit quality and credit rating. In summary, the Company's projection of the working capital cash balance of $56.6 million results in a level that is needed, reasonable, balanced, and adequately minimizes the Company's financial and credit risk.

V. EVALUATION OF SECURITIZATION AS A COST RECOVERY MECHANISM FOR DEFERRED STORM COSTS

Q. As explained in Company witness Hannah L. Patton's direct testimony, the Commission has directed the Company to provide a comprehensive comparison of potential cost-recovery options for deferred storm costs including securitization. Is securitization a suitable and cost-effective recovery method for customers?

A. No. The storm cost regulatory asset of $52 million is not large enough to make securitization a cost-effective recovery option for customers. Securitization is designed to replace higher-cost debt and equity with lower-cost securitization bonds. However, there is a substantial amount of fixed costs associated with securitization financing including bank fees, special-purpose entity formation costs, legal, auditing, and rating agency fees, as well as ongoing administrative expenses. These costs are largely fixed regardless of the

securitized amount. Therefore, when the securitized amount is small (as in the case of the Company's deferred storm costs), the fixed costs greatly offset, and can potentially eliminate, the benefit of lower interest rate securitization financing.

Q. How would the transaction costs of a $52 million deferred storm cost securitization compare to the Company's most recent securitization?

A. In December 2023, the Company issued $646 million of securitization bonds with $5.8 million in up-front fees representing 0.9% of the issuance amount. Assuming the same fixed fees and a variable bank underwriting fee (equal to 0.4% of the issuance amount) were applied to a much smaller $52 million securitization, the up-front costs would total $3.7 million, or 7% of the issuance amount. This dramatic increase in relative cost is shown in the following chart:

Securitization Cost Analysis	2023 Securitization	Pro-Forma Securitization
Securitization Issuance Amount	$ 646.0	$ 52.0
Bank Underwriting Fee (0.4%)	$ 2.6	$ 0.4
Other Administrative Costs*	3.3	3.3
	$ 5.9	$ 3.7
Fees as a % of Issuance Amount	0.9%	7.1%

*Legal, auditor, rating agency and other admin fees assumed to be the same.

The transaction costs for a $52 million securitization are thus disproportionately higher and are economically inefficient. In addition, the Company found no evidence of other utilities securitizing cost amounts significantly below $100 million, reinforcing the conclusion that such a transaction is economically unsound. For these reasons, securitization of deferred storm costs is not a suitable and cost-effective recovery method for customers.

Q. Company witness Patton proposes that the deferred storm cost regulatory asset be recovered over three years. Does this proposed recovery period have credit metric implications for the Company?

A. Yes. As discussed earlier in my testimony, the Company is already experiencing credit metric pressure due to the number of cost deferral mechanisms that require the Company to fund customer focused programs without contemporaneous cash recovery. These deferrals preserve non-cash earnings but reduce cash flow and increase long-term financing needs, which in turn weaken key credit metrics. Recovering the deferred storm cost regulatory asset over three years, as proposed by Company witness Patton, helps mitigate this pressure. As the regulatory asset earns no return, not even a short-term debt rate, the Company must fully absorb the financing burden of carrying this regulatory asset until it is recovered from customers. A three-year recovery period, as opposed to a longer period, accelerates the return of cash the Company has already expended, improving cash flow and reducing the need for incremental debt. Accordingly, the three-year period proposed by Witness Patton provides a modest but meaningful credit metric benefit compared to a longer recovery period.

VI. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2025, adjusted for the known and expected changes in long-term debt, common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time that rates are expected to be in effect.

As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.59%. Also, securitization is not a suitable and cost-effective recovery method for customers. Finally, the Company's projected cash balance for the test year in this case should be based on a 5-year historical average, which results in a balance of $56.6 million.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Sales Forecasting Analyst in Financial Planning & Analysis.

Q. Please describe your qualifications.

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration in International Management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January 2013, I accepted the position of Senior Rate Analyst II. In 2020, I was promoted to Senior Analyst III, and again in 2023 to Principal Sales Forecasting Analyst, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric deliveries and customer forecasts, sponsoring the deliveries and customer forecast testimony and exhibits, industry research, and various economic studies. Also, I am responsible for creating the Company's revenue forecast related to the electric business.

Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have presented the Company's electric business sales and revenues forecasts in the following cases:

U-17771	2016 – 2017 Energy Optimization Plan;
U-17990	General Electric Rate Case;
U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
U-18231	2017 Biennial Renewable Energy Plan;
U-18261	Amended Energy Optimization Plan;
U-18322	General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	General Electric Rate Case;
U-20165	2018 Integrated Resource Plan ("IRP");
U-20219	2019 PSCR Plan;
U-20372	2019 Energy Waste Reduction ("EWR") Electric and Gas Plan;
U-20525	2020 PSCR Plan;
U-20697	General Electric Rate Case;
U-20802	2021 PSCR Plan;
U-20875	2022-2025 EWR Plan;
U-20963	General Electric Rate Case;
U-21048	2022 PSCR Plan;
U-21090	2021 IRP;
U-21257	2023 PSCR Plan;

U-21321	2024-2025 EWR Plan;
U-21389	General Electric Rate Case;
U-21423	2024 PSCR Plan;
U-21585	General Electric Rate Case;
U-21592	2025 PSCR Plan;
U-21680	2025 EWR Plan;
U-21816	Amended RE Plan;
U-21870	General Electric Rate Case; and
U-21873	2026 PSCR Plan.

Furthermore, I have been involved in preparing the forecasts sponsored by other Company witnesses in prior cases before the MPSC.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my direct testimony is to present the Company's electric revenues, deliveries, generation requirements, and peak demands for the split-test year May 2027 – April 2028.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (EMB-1)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Historical;
Exhibit A-15 (EMB-2)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Projected;
Exhibit A-15 (EMB-3)	Schedule E-2	Test Year Total Company Electric Revenues & Deliveries;
Exhibit A-15 (EMB-4)	Schedule E-3	Electric Deliveries & Customer Counts by Rate Category;

Exhibit A-15 (EMB-5)	Schedule E-4	Calculation of Annual System Load Factor; and
Exhibit A-45 (EMB-6)		Estimated Electric Rate Case PSCR Factor.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes.

SECTION I. FORECASTING METHODOLOGY

Q. What is forecasting?

A. Forecasting involves estimating future values based on historical data and assumptions, and in this testimony the Company presents forecasts of electric deliveries and peak demand for its electric service territory.

Q. Are there different types of analyses used in preparing forecasts?

A. Yes.

Q. What type of analysis was utilized for forecasting electric deliveries and peak demand for the Company's electric service territory?

A. Statistical modeling, specifically regression analysis, was used to forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.

A. The electric deliveries and peak demand forecasts are developed using a combination of econometric modeling and end-use analytical techniques.

Q. What process is involved in developing the electric deliveries forecast?

A. The electric deliveries forecast is developed using a six-step process. First, class-level historical data, including monthly electric deliveries, customer counts, billing days, seasonal indicators, and daily temperature data, are collected and incorporated into the

modeling framework. Daily temperature data are converted to monthly heating degree days ("HDD") and cooling degree days ("CDD") prior to use.

Second, economic and demographic variables from S&P Global are incorporated, including historical data beginning in 2001 and projections through the forecast horizon. Third, externally developed electric-use forecasts, covering electric vehicles, large customer production, distributed generation ("DG"), and EWR programs, are added. These inputs are exogenous to the models and reflect Commission-adopted assumptions, industry expectations, or end-use analyses.

Fourth, all inputs are reviewed for data quality, with errors corrected or excluded as appropriate. Fifth, the regression models are executed and evaluated using standard statistical metrics. As part of this step, a calibration variable is included in each of the class-specific regression models (residential, commercial, and industrial) to account for normal seasonal and month-to-month variation in deliveries. This variable provides a structured way to capture monthly patterns without over-specifying the model. Finally, the regression-based results are combined with the external forecasts to produce the overall electric deliveries forecast.

In summary, this process integrates historical data, economic and end-use projections, and rigorous statistical evaluation to develop a comprehensive and internally consistent electric deliveries forecast.

Q. After completing the regression modeling steps you described, does the Company make any additional adjustments to the electric deliveries forecast?

A. Yes. After the regression models are executed and evaluated, the Company applies a set of manual, judgment-based adjustments to ensure the final forecast reflects the most current

trends and conditions in the service territory. While the regression models provide a statistically sound baseline, they rely on long-term historical data. As noted earlier in my testimony, the models incorporate "historical data beginning in 2014 and projections through the forecast horizon," which means that very recent developments may not yet be fully captured. These manual adjustments, what I refer to as the hybrid method, allow the Company to integrate both quantitative model output and professional expertise.

Q. Why is this hybrid method necessary if the regression models already include weather, economic, and demographic variables?

A. Regression models are essential tools, but they cannot fully account for emerging trends, structural changes, or recent shifts that may not be reflected in long-term historical data. For example, changes in customer behavior, evolving electric vehicle ("EV") adoption patterns, or short-term economic fluctuations may not be fully represented in the model's historical window. The hybrid method ensures the forecast remains responsive, reasonable, and aligned with observed conditions, rather than relying solely on statistical output.

Q. What types of manual adjustments are typically made as part of this hybrid method?

A. Manual adjustments are applied to align the model output with recent growth trends and current data on key drivers such as EV adoption, economic activity, and customer counts. These adjustments are modest, targeted, and grounded in observable data. They do not replace the regression model; rather, they refine it to ensure the final forecast is both statistically sound and operationally realistic.

Q. Is the hybrid method a standard practice in electric load forecasting?

A. Yes. The hybrid approach, combining quantitative modeling with expert judgment, is widely used in the forecasting profession. Electric load forecasting requires both analytical

precision and adaptive insight. Regression models provide consistency and scalability, while expert judgment allows forecasters to incorporate the most recent information and contextual understanding. Together, these elements produce forecasts that are more accurate, more resilient, and better aligned with real-world conditions. As the authors of a recent study observed, "Comparative studies of quantitative methods and human judgement show that (1) neither method is universally superior, and (2) the better method varies…suggesting that (3) the two approaches can complement each other to yield more accurate and resilient models."[1]

Q. Where in your testimony are the specific delivery adjustments associated with this hybrid method discussed?

A. The detailed adjustments associated with the hybrid method are presented in Section IV of my testimony, where I discuss the historical and forecasted electric deliveries for each major customer class. That section includes the class-level impacts, the treatment of **Long-**Term Industrial Load Retention Rate ("LTILRR") and Large Economic Development Rate ("LEDR") load, and the adjustments necessary to align the regression-based forecast with expected test-year conditions.

Q. What is the process involved in developing the electric peak demand forecast?

A. The Company's peak demand forecast methodology is generally consistent with the approach used to develop the electric delivery forecast. The first step in the process is the compilation and importation of the Company's historical monthly system peak demand data into the demand modeling framework. The associated explanatory variables include

[1] Zellner, M., Abbas, A. E., Budescu, D. V., & Galstyan, A. (2021). *A survey of human judgement and quantitative forecasting methods*. Royal Society Open Science, 8(201187). Abstract. https://doi.org/10.1098/rsos.201187.

corresponding daily minimum and maximum temperatures, forecasted base electric deliveries, seasonal indicator variables, and customer counts. An average of the daily minimum and maximum temperatures is calculated and used to develop peak CDD and HDD variables, which are subsequently incorporated into the modeling framework.

The second step involves a comprehensive review of the imported data to identify and address any anomalies, inconsistencies, or data quality issues prior to model estimation. This review ensures that the underlying dataset is reasonable and suitable for econometric analysis.

The third step consists of estimating an econometric peak demand model. Observed monthly system peak demand is regressed against seasonal indicator variables, temperature-based degree day variables, and forecasted base electric sales. This regression framework captures the relationship between peak demand, weather conditions, seasonal patterns, and underlying load growth.

The final step in the peak demand forecasting process integrates the results of the econometric model with the Company's projected peak demand adjustments. These adjustments reflect the anticipated impacts of specific programs, tariffs, and customer effects, including: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs; (3) Conservation Voltage Reduction ("CVR"); (4) the Residential Summer On-Peak ("RSP") rate; large customer impacts; and EV adoption. The combined results represent the Company's forecast of monthly system peak demand for planning and regulatory purposes.

Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?

A. The Company uses regression modeling to develop its electric delivery and customer count forecast models based on relevant weather and economic variables. Each model is evaluated and selected based on its ability to reasonably explain historical variation in the underlying data, as well as the statistical reliability of the estimated coefficients.

Model performance is assessed using established statistical diagnostics, with particular emphasis on the adjusted coefficient of multiple determination (adjusted R^2), which measures the explanatory power of the model while accounting for the number of independent variables, and the Mean Absolute Percent Error ("MAPE"), which evaluates the model's historical forecasting accuracy. Together, these metrics are used to confirm that the selected models provide a reasonable fit to historical data and are appropriate for forecasting purposes.

Q. How are R_a^2 and MAPE used in evaluating the model?

A. Both statistical tests are used to evaluate how well the models fit the historical data and provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, MAPE is used to measure model errors in which

smaller values suggest better model performance. MAPE values of less than 3% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

Q. What criteria are used when considering the t-statistics and p-values associated with the model coefficients?

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("β") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistics and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above two and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t statistics below two and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within the statistically significant ranges described above and are, therefore, considered relevant.

Q. What software is used to create these regression models for the energy, demand, and customer count projections? And why?

A. The Company uses MetrixND to develop its regression models for energy, peak demand, and customer count projections. The Company has relied on MetrixND for these purposes for at least the past 15 years, which provides continuity and consistency in its forecasting methodology over time.

MetrixND is a commercially supported forecasting software package licensed by Itron, Inc., a global technology company that provides utility-focused software solutions and professional services. The software is specifically designed for energy and demand forecasting applications and supports econometric modeling using weather, economic, and customer-related variables.

The Company considers MetrixND to be an industry-standard tool, as it is widely used by electric utilities, independent system operators, municipal utilities, cooperatives, and other energy service providers throughout the industry. Its widespread adoption, established analytical capabilities, and long-term use by the Company support the reasonableness and reliability of the forecasting results produced using this platform.

SECTION II. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

Q. What are the key variables that affect the electric deliveries and demand forecasts?

A. The Company's electric deliveries and demand forecasts are influenced by several primary categories of variables, including weather, economic conditions, and demographic trends. These variables collectively explain the majority of historical variation in electric usage and peak demand.

In addition to these core drivers, the Company incorporates variables that account for the impacts of specific programs, technologies, and customer-related factors expected to affect future electric usage. These include variables related to EWR programs, DG, EV adoption, large industrial customer impacts, and a variable designed to capture the effects of the COVID-19 pandemic on historical consumption patterns.

Q. What is the impact of weather on the forecasting process, and what assumptions are made regarding weather variables in the forecast?

A. Weather is the primary driver used in the Company's forecasting models to capture seasonal variation in electric deliveries and peak demand throughout the year. To reflect typical weather conditions, the Company uses a 15-year historical average of HDD based on a 60-degree Fahrenheit base (HDD60) and CDD based on a 60-degree Fahrenheit base (CDD60) in its econometric models.

The HDD60 variable captures the impact of colder-than-normal weather conditions, while the CDD60 variable captures the impact of warmer-than-normal weather conditions. The use of long-term average weather assumptions is consistent with standard forecasting practice and is intended to produce forecasts reflecting normal, or expected, weather conditions rather than short-term variability.

Q. Please explain the calibration variable used in the regression modeling. What purpose does the variable serve?

A. The calibration variable is used to capture seasonality and month-to-month variations in deliveries. Conceptually, it serves a role similar to monthly binary variables in a regression model, with each month contributing a coefficient that reflects its unique seasonal effect. Rather than including all twelve monthly binary variables, the calibration approach embeds

these monthly effects into a single structured variable to avoid the problem of multicollinearity. Multicollinearity is a condition where two or more independent variables are so closely related that they are correlated to one another, which makes a model unstable and unreliable because it becomes mathematically difficult for the regression to determine which variable is actually driving the result. Including all twelve monthly indicators also leads to what is known as the dummy-variable trap, where the model becomes mathematically unsolvable because the variables perfectly overlap with one another.

The calibration variable avoids these issues by allowing each month to retain a distinct coefficient while preventing the model from becoming over-specified. From a mathematical perspective, this calibration variable is functionally equivalent to using eleven monthly binary variables, but it achieves the same outcome in a more efficient and stable manner for the regression model.

Q. How are these calibration values derived?

A. The calibration values are derived directly from the regression model. Each month's underlying seasonal effect is first estimated through its binary indicator within the model. These estimated coefficients are then combined into the calibration variable, which represents the full set of monthly seasonal adjustments in a single, consolidated form. This allows the model to retain the month-by-month seasonal structure while maintaining numerical stability and interpretability.

Q. What are econometrics or econometric techniques?

A. Econometrics refers to a set of quantitative economic and statistical techniques used to model and analyze relationships among economic variables. These techniques rely on mathematical and statistical methods to explain historical behavior and to develop

forecasts. A primary econometric tool used by the Company is regression analysis, which is applied to estimate the relationships between electric deliveries or demand and explanatory variables such as weather, economic conditions, and customer growth.

Q. What impact does the economy have on the forecasting process, and what assumptions are made regarding economic variables in the forecast?

A. The Company incorporates economic indicators into its forecasting models to reflect expected growth in electric usage associated with changes in economic activity within its service territory. Key economic variables include employment levels and industrial production, which are particularly important drivers of commercial and industrial electric consumption.

Economic forecasts used in the Company's modeling process are obtained from S&P Global, a nationally recognized provider of economic data and analysis. These externally developed forecasts are used to ensure that the Company's assumptions regarding economic growth are consistent with widely accepted economic outlooks and reflect reasonable expectations for future conditions.

Q. What is the impact of demographics on the forecasting process?

A. Demographic trends, particularly population growth, are used to inform the Company's long-term customer forecasts. Population projections are incorporated to account for changes in the number and composition of customers over time.

Specifically, the commercial customer forecast is derived in part from county-level population projections provided by S&P Global. These demographic projections help capture long-term growth trends and support the reasonableness of the Company's customer and energy forecasts for planning and regulatory purposes.

SECTION III. TEST YEAR ELECTRIC REVENUES

Q. Please describe Exhibit A-15 (EMB-3), Schedule E-2.

A. Exhibit A-15 (EMB-3), Schedule E-2, is a single-page exhibit that summarizes the component differences between the 2025 historical revenues and deliveries and the forecasted test year revenues and deliveries used in this case.

Q. Please explain the Weather-Normalization column, column (f), in Exhibit A-15 (EMB-3), Schedule E-2.

A. Exhibit A-15 (EMB-3), Schedule E-2, represents a "walk" from the 2025 historical year to the projected test year. The historical year represents actual revenues and deliveries, which are not weather-normalized. Since the Company's projections are weather-normalized, column (f) represents the 2025 impact of weather-normalizing the historical actuals.

Q. Please explain the Pro Forma column, column (h), in Exhibit A-15 (EMB-3), Schedule E-2.

A. The Pro Forma column in this exhibit represents the difference in revenues due to the difference in rates between the historical year 2025 and the projected test year. 2025 revenues were based on customer rates established by the Commission's March 2025, Order in Case No. U-21585 ("Case No. U-21585 Order"), while the test year revenues are projected revenues based on the rates established by the Commission's March 2026 Order in Case No. U-21870 ("Case No. U-21870 Order").

Q. Please explain the LTILRR and LEDR adjustment, shown in column (e), to deliveries (MWh) and revenues in Exhibit A-15 (EMB-3), Schedule E-2.

A. The LTILRR and LEDR are specialized industrial rates. The LTILRR was approved by the Commission in its Case No. U-20697 Order to allow customized electric rates

(LTILRR) for customers meeting certain criteria. The LEDR was approved by the Commission in its Case No. U-21160 Order. As such, the Company has excluded revenues and deliveries of certain large industrial customers that receive service under the LTILRR and LEDR from base tariff revenues, as well as deliveries in the test year. Instead, these projected test year revenues are reflected in the Miscellaneous Revenues line in Exhibit A-15 (EMB-3), Schedule E-2, column (e), line 25. Company witness Michael C. Grondin supports the details behind these LTILRR/LEDR projected revenues and deliveries.

Q. What credit revenues are included in the test year projections related to the Residential Senior Citizen ("RSC") and Residential Income-Assistance ("RIA") provisions?

A. The average test year customer count projections for the RSC and RIA provisions are 398,818 and 68,284 customers, respectively. Based on these projected counts, the test year includes revenue credits of $19.1 million for the RSC provision (398,818 customers × $4 credit × 12 months) and $9.1 million for the RIA provision.

The RIA credit revenue consists of $6.0 million for 62,084 RIA customers receiving an $8 monthly credit (62,084 × $8 × 12 months) and $3.1 million for 6,200 Low-Income Assistance Credit ("LIAC") customers receiving a $42 monthly credit (6,200 × $42 × 12 months), as approved in the Commission's Order in Case No. U-21870.

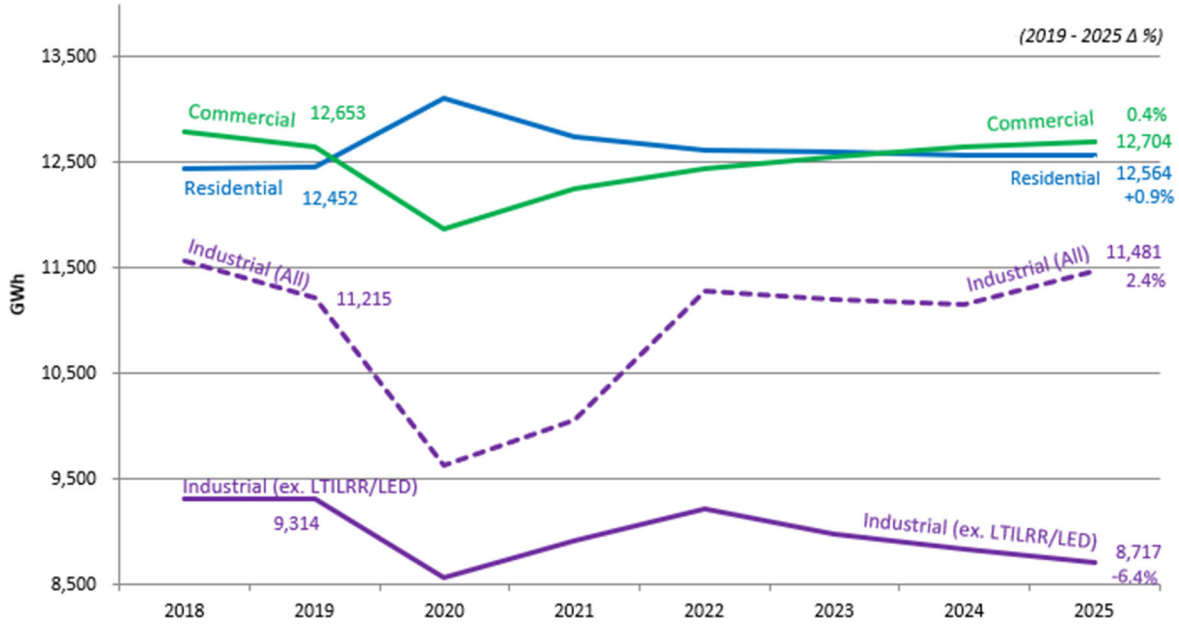
The associated reduction in base tariff revenues is reflected in Exhibit A-15 (EMB-3), Schedule E-2, column (j), line 1.

SECTION IV. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. How have the Company's weather-normalized electric deliveries changed from 2019 (pre-pandemic) through the 2025 historical year?

A. From 2019 (pre-pandemic) through the 2025 historical year, the Company's weather-normalized electric deliveries have remained essentially flat, increasing by only 0.1% overall. During this period, deliveries in the industrial class declined by 2.4%, while the commercial class decreased by 0.4%. In contrast, the residential class experienced a 0.9% increase. These trends are illustrated in Figure 1.

Figure 1 Historical Electric Calendar, Weather-adjusted Deliveries by Class



Q. What is the cause of the sudden Residential increase and Commercial/Industrial ("C&I") decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?

A. Following 2019, the Company's electric deliveries were significantly affected by the COVID-19 pandemic. In 2020, pandemic-related behavioral changes and government-mandated restrictions resulted in increased levels of remote work and reduced

or suspended operations for many commercial and industrial customers. These conditions led to an increase in residential electric usage and a corresponding decrease in C&I deliveries, even on a weather-normalized basis.

Q. How did COVID-19 affect the Company's different customer classes?

A. COVID-19 and the resulting pandemic had opposite impacts on the Company's residential and C&I customer classes. In 2020, weather-adjusted residential deliveries increased by 5.2% compared to 2019. In contrast, weather-adjusted C&I (excluding LTILRR) deliveries declined by 6.2% and 8.0%, respectively.

Q. Earlier in this direct testimony, you mentioned the use of class-specific manual adjustments to electric deliveries. What are the manual adjustments related to the test-year residential customer-class deliveries?

A. A total downward manual adjustment of 450 GWh was applied to reduce the test-year residential cycle-billed deliveries to 12,514 GWh. This adjustment brings the regression-based forecast into alignment with recent weather-normalized trends and expected test-year conditions. Of this total, 14 GWh represents an upward adjustment associated with electrification assumptions, as discussed later in this testimony.

The remaining (464 GWh) reflects a downward adjustment needed because, although the regression models produced statistically strong results—such as high R-squared values and low error metrics—their test-year forecasts were materially higher than recent actual delivery levels. This discrepancy indicated that the models were capturing long-term historical relationships but not fully reflecting more recent structural changes in customer usage patterns. To ensure the forecast aligned with observable and

persistent trends in the most recent years (see Figure 2), these manual adjustments were required.

Q. What are the manual adjustments related to the test-year commercial bundled customer class deliveries?

A. To arrive at the test-year commercial bundled delivery total of 11,522 GWh, a 30 GWh manual adjustment was applied, of which 10 GWh represents an upward adjustment related to electrification. This adjustment brings the regression-based forecast into alignment with recent weather-normalized trends and expected test-year conditions.

In addition, a net-zero shift of 279 GWh was made between the commercial and industrial customer classes. This adjustment reflects a historical reclassification in 2015 between secondary and primary rate categories, which has slightly distorted the regression models. The adjustment ensures that the test-year forecast is consistent with that reclassification.

As shown in Figure 3, the resulting test-year commercial deliveries align well with the historical trend.

Q. What are the manual adjustments related to the test year industrial bundled customer class deliveries?

A. A manual adjustment of 338 GWh was applied to increase the test-year industrial bundled cycle-billed deliveries (excluding LTILRR/LED) to 5,827 GWh. This adjustment brings the regression-based forecast into alignment with recent weather-normalized trends and expected test-year conditions.

In addition, a net-zero adjustment of (279 GWh) was made between the commercial and industrial customer classes. This shift reflects a historical 2015 reclassification

between secondary and primary rate categories, which has slightly distorted the regression models. The adjustment ensures that the test-year forecast remains consistent with that reclassification.

As shown in Figure 4, the resulting test-year industrial deliveries align well with the historical trend.

Q. What are the electric delivery expectations for the test year used in this case?

A. Test-year electric deliveries are projected to be 38,677 GWh, as shown in Exhibit A-15 (EMB-2), Schedule E-1. This reflects an approximate two-year compound annual growth rate ("CAGR") of 2.4% compared to the weather-normalized 2025 historical year level of 36,878 GWh, as shown in Exhibit A-5 (EMB-1), Schedule E-1, page 2. Much of this growth is attributable to LTILRR/LED load. When LTILRR/LED is excluded, the two-year CAGR is –0.8%.

Q. What information is presented in Exhibit A-15 (EMB-4), Schedule E-3, and how should it be interpreted?

A. Exhibit A-15 (EMB-4), Schedule E-3 is a one-page exhibit that presents annual electric deliveries and customer counts by rate category from the historical year through the test year. The historical year 2025 values align with the figures reported to the MPSC in Form P-521, and the delivery data for that year is not weather-adjusted.

Q. What explains the decrease in deliveries from the historical year to the test year shown in this exhibit?

A. The decrease in deliveries from the historical year to the test year primarily reflects the removal of non-jurisdictional load from the test-year forecast. Specifically, deliveries to the Company's wholesale customer cease after 2024, resulting in no wholesale deliveries

in the test year. In addition, Grand Rapids Streetlighting is excluded from test-year deliveries and instead reflected in miscellaneous revenues, consistent with the treatment approved in the prior rate case.

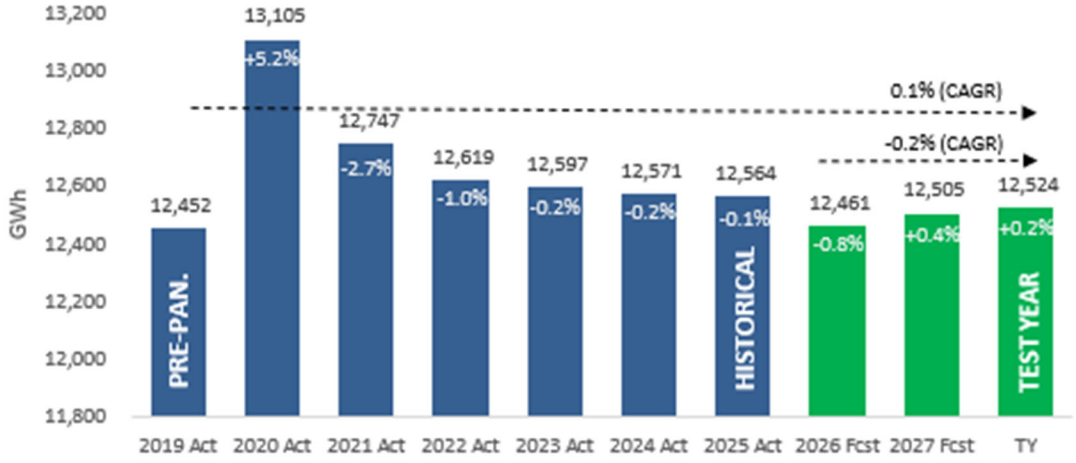
Beyond these structural adjustments, modest reductions across several bundled customer classes contribute to the overall change in deliveries. LTILRR and LED volumes are excluded from both the historical year and the test year in this exhibit and therefore do not contribute to the difference between the two periods.

Q. What do the historical and projected deliveries look like in the residential customer class?

A. The residential customer class is projected to grow at a compound annual growth rate of approximately 0.1% from 2019 (pre-pandemic) through the test year. As illustrated in Figure 2, with actual deliveries shown in blue and forecasted deliveries shown in green, residential usage increased materially in 2020, reflecting the significant shift toward working from home during the COVID-19 pandemic. Residential deliveries increased by 5.2% year-over-year in 2020. In 2021, deliveries declined by 2.7% as some customers returned to in-person work, partially reversing the pandemic-related increase.

As customer behavior continues to normalize relative to pre-pandemic work patterns, residential deliveries are expected to stabilize over the forecast horizon. Consistent with this trend, Figure 2 shows minimal growth between the 2025 historical year and the test year, corresponding to a -0.2% CAGR over that period. This limited growth reflects offsetting dynamics, with incremental EV load largely counterbalanced by EWR savings. Residential customer count growth over the period remains modest.

Figure 2



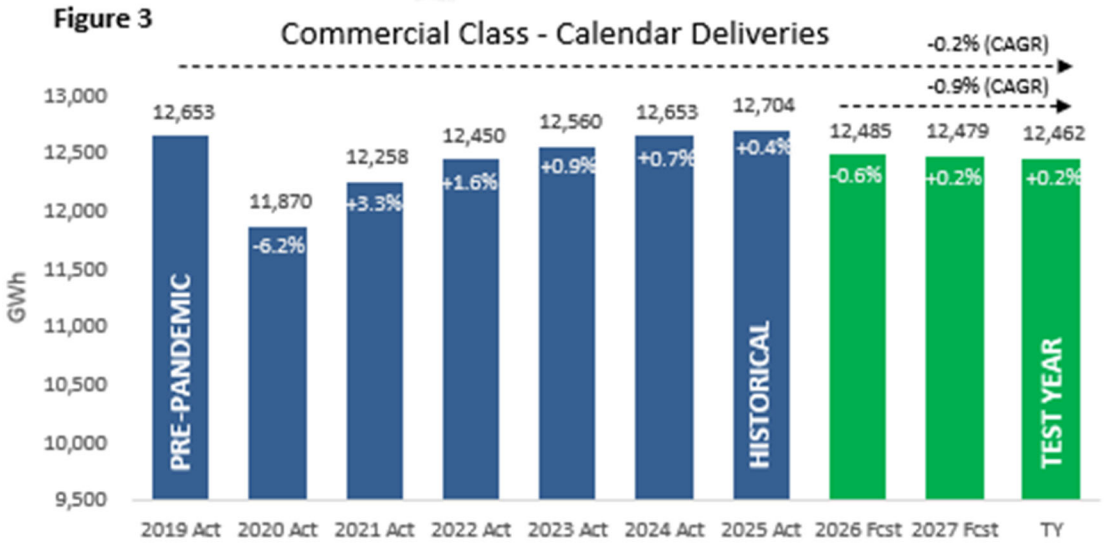
Q. What do the historical and projected deliveries look like in the commercial customer class?

A. The commercial customer class is projected to decline at a compound annual growth rate of approximately -0.2% from 2019 (pre-pandemic) through the test year. As illustrated in Figure 3, with actual deliveries shown in blue and forecasted deliveries shown in green. Commercial usage declined significantly in 2020 due to the adverse impacts of the COVID-19 pandemic on retail establishments, schools, restaurants, and other commercial customers. Commercial deliveries decreased by 6.2% year-over-year in 2020. In 2021, deliveries increased by 3.3%, reflecting a partial recovery in these sectors.

Commercial deliveries are projected to stabilize over the forecast horizon; however, test-year deliveries remain below 2019 levels, consistent with a –0.2% CAGR relative to the pre-pandemic period. A similar pattern is observed when comparing the 2025 historical year to the test year, where commercial deliveries decline at a –0.9% CAGR. This reduction is driven primarily by ongoing EWR savings, which exert a persistent downward influence on commercial usage. Although electric vehicle load represents a growing source of

consumption within the commercial class, this growth only partially offsets the EWR-related reductions. The net effect of these opposing forces results in a modest decline in commercial class load over the forecast period.

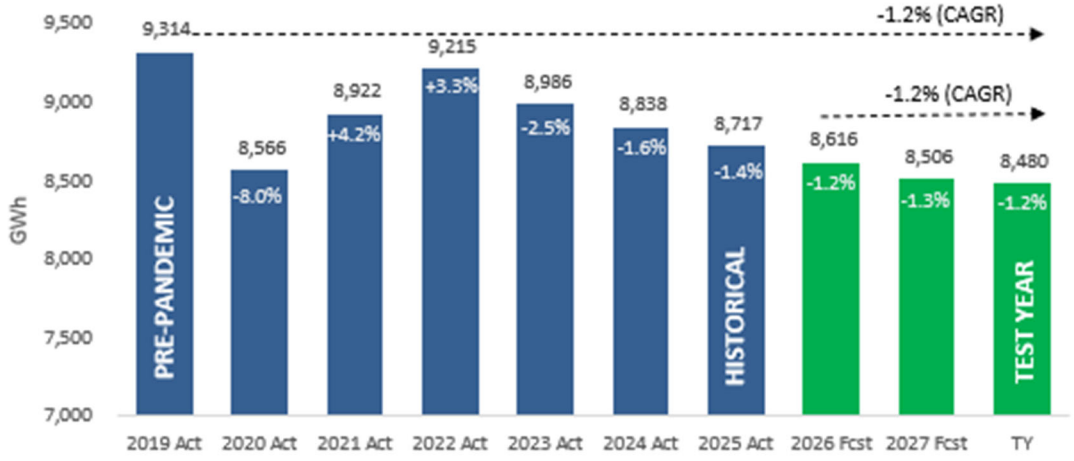
Figure 3



Q. What do the historical and projected deliveries look like in the industrial customer class?

A. The industrial class is projected to decline at a –1.2% CAGR from the pre-pandemic period through the test year. In 2020, it experienced a sharper contraction than the other classes, with an 8.0% year-over-year decrease (see Figure 4). By 2022, however, the industrial class had recovered most of the sales lost during the pandemic. From the historical year to the test year, EWR pressures are expected to push deliveries downward again.

Figure 4 Industrial (Ex. LTILRR/LED) Class - Calendar Deliveries



Q. How is electrification incorporated into the electric deliveries forecast?

A. Electrification is incorporated into the electric deliveries forecast by identifying end-uses where residential and commercial customers are expected to shift from fossil-fuel energy to electricity, such as space heating, water heating, and transportation. The Company evaluates expected adoption levels and converts these adoption estimates into incremental GWh impacts. These incremental electrification loads are then added to the regression-based forecasts for the residential and commercial customer classes. At this stage, electrification remains in its infancy and has only a modest impact on the overall forecast.

Q. How much electrification-related load is included in the test-year electric deliveries forecast for the residential and commercial customer classes?

A. The test-year forecast includes 24 GWh of electrification-related load for the residential and commercial customer classes, allocated as follows:

- Residential: 14 GWh (approximately 0.12% of the residential test-year forecast)
- Commercial: 10 GWh (approximately 0.09% of the commercial test-year forecast)

These adjustments represent early-stage adoption of electric technologies and remain relatively immaterial to the overall forecast. They are incorporated as upward adjustments to the regression-based forecasts and are reflected in the manual adjustments described earlier in this testimony.

Q. Does the test-year delivery forecast anticipate an increase in EVs in the Company's service territory?

A. Yes. The Company expects the number of electric vehicles in its service territory to increase from 50,617 in 2025 to an estimated 131,549 EVs by the test year, representing a 51% CAGR. These 131,549 EVs are projected to contribute approximately 489 GWh of incremental annual electric load.

Q. Is the increased load due to EVs concentrated only around the residential customer class?

A. No. Of the total 489 GWh of incremental EV load anticipated in the test year, 319 GWh (65%) is expected to occur in the residential sector, while 170 GWh (35%) is allocated to the business sector.

Additional details regarding EV adoption and load impacts are addressed in the testimony of Company witness Alex M. Gast.

Q. Does the test-year delivery forecast include any impact due to DG?

A. Yes. DG remains a relatively small portion of total deliveries in the test year. DG is expected to grow at a faster rate than historical levels. In 2026, DG is projected to reduce residential deliveries by 47 GWh, which represents 0.38% of total residential load. By the test year, DG-related reductions are expected to increase to 54 GWh, or 0.43% of total residential load.

Q. To what extent has the Company reflected future EWR in the electric deliveries forecast you are sponsoring in this case?

A. The Company was required under the 2008 Energy Law, Public Act 295, to help its electric customers reduce their energy usage by at least 1% per year. In 2016, State lawmakers reinforced the use of demand-side resources, such as EWR, by amending the law to encourage utilities to expand the use of demand-side resources beyond the mandated floors. The Governor signed the 2016 Energy Laws, Public Acts 341 and 342, on December 21, 2016. Although the Company is encouraged to help its customers reduce energy waste by at least 1% per year under the law, it is also encouraged to cost-effectively expand its use of demand-side resources. As such, the Company has updated the electric deliveries forecast based on its commitment to help customers reduce energy waste by at least 1.5% per year since 2017.

Q. What level of EWR savings is included in the test-year deliveries?

A. From 2025 through the test year, the Company is expected to increase its EWR savings level to 2%, consistent with the assumptions filed in the Company's most recent IRP, Case No. U-21090. In the test year, the Company's projected EWR savings remain at 2.0% overall. Within that total, the residential class is projected to achieve 1.4% savings, while the business class is projected to achieve savings of approximately 2.0%.

Q. Please describe the process used to determine the Company's total generation requirements.

A. The forecasted total electric deliveries are increased by a line loss factor as determined by the 2024 System Loss Study to arrive at the Company's total generation requirements, i.e.

system output, shown in Exhibit A-15 (EMB-2), Schedule E-1, and Exhibit A-15 (EMB-5), Schedule E-4.

Q. Is the 2024 System Loss Study the latest available?

A. The 2024 System Loss Study was the latest available at the time the test-year projections were created for this case.

Q. Please explain Exhibit A-45 (EMB-6).

A. Exhibit A-45 (EMB-6) calculates the projected test year PSCR Factor based on the electric deliveries and power supply expenses used in this case.

SECTION V. FORECASTED PEAK DEMAND

Q. What are the expectations for growth in peak demand?

A. The Company forecasts peak demand using regression analysis based on the projected level of electric deliveries. Weather-normalized peak demand grew at a 1.6% CAGR from 2003 to 2007, but much of that growth was reversed during the 2007–2009 recession. Looking ahead, peak demand is expected to increase by approximately 0.3% per year from 2026 through 2030. The monthly system-level results of the electric peak demand forecast are presented in Exhibit A-15 (EMB-5), Schedule E-4.

Q. What is the impact to the peak demand forecast from the Company's Smart Energy programs?

A. The peak demand forecast is reduced by approximately 38 MW in 2026 and through the test year for the Company's DPP programs, which consist of Peak Time Rewards and Critical Peak Pricing.

Q. Are there any other adjustments to peak demand?

A. Yes. In 2026, EWR and CVR measures are estimated to reduce peak demand by 1047 MW and 69 MW, respectively. This cumulative reduction to peak demand is projected to increase to 1121 MW (EWR) and 79 MW (CVR) in the test year.

Q. Are capacity-side demand response ("DR") resources accounted for in the Company's peak demand forecast?

A. No. Capacity-side DR resources, such as Residential AC Peak Cycling and C&I DR, which includes Rate GI and Rate EIP, are registered with Midcontinent Independent System Operator, Inc. and are accounted for outside of this peak demand forecast. Company witness Joshua W. Hahn supports the capacity-side DR in his testimony.

Q. To what extent is the Company's RSP rate expected to impact peak demand?

A. Rate RSP is expected to reduce the Company's peak demand by approximately 95 MW in the test year.

Q. What process is used to identify the peak demand impacts of the Company's EWR programs?

A. The Company developed hourly load profiles for the EWR programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, employer, and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") on behalf of Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor of Arts degree in Economics and Finance from Simmons College and a Master of Science degree in Economics from Boston University, with over 30 years of experience consulting to regulated utilities and the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional and educational background is presented as Attachment A to Exhibit A-14 (AEB-1), Schedule D-5.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the return on equity ("ROE") for Consumers Energy's electric utility operations to be used for ratemaking purposes.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. My analysis and recommendations are supported by data presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 1 through 29, which were prepared by me or under my direction.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my analyses and the analytical basis for the recommendation of the appropriate ROE for the Company.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors that you consider your analyses and upon which you base your recommended ROE.

A. The key factors that I have considered in developing my recommendation regarding the appropriate ROE for the Company in this proceeding are:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access

to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.[1]

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)

- Company-specific considerations, since although the companies in my proxy group are generally comparable to the Company, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. Briefly, how have you developed your recommended cost of equity for the Company?

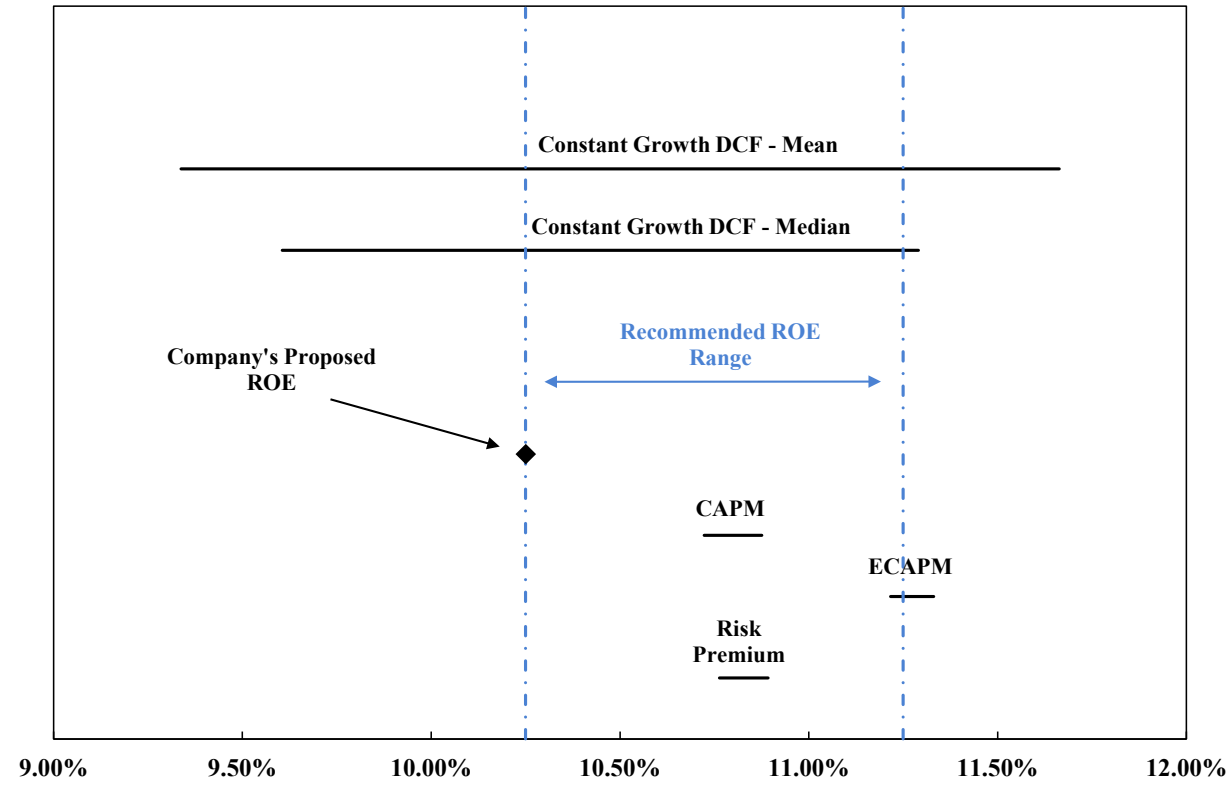
A. I estimate the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the impact of flotation costs. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

[1] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

Q. What are the results of the models that you have used to estimate the cost of equity for Consumers Energy?

A. Figure 1 summarizes the range of results produced by the models that I have conducted based on data through the end of March 2026.

Figure 1: Summary of Cost of Equity Analytical Results



Q. What is your conclusion regarding the appropriate authorized ROE for the Company in this proceeding?

A. Considering the analytical results presented in Figure 1, current and projected capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25% to 11.25% is reasonable,

and within that range, I conclude that the Company's requested ROE of 10.25% is reasonable.

III. REGULATORY GUIDELINES

Q. Please describe the guiding principles used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. For example, in its decision in Case No. U-20963, the Commission stated:

> The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States (U.S.) Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).[3]

This guidance is in accordance with my view that an authorized rate of return on equity must be sufficient to enable regulated companies such as Consumers Energy the ability to attract equity capital on reasonable terms.

Q. How did the Court connect achieving a fair rate of return to providing utility service to customers?

A. The Court stated in *Bluefield* that a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. An authorized ROE that is adequate to attract capital at reasonable terms enables a utility to continue to provide safe, reliable service while maintaining its financial integrity. The authorized return should be commensurate with returns expected elsewhere in the market for investments of comparable risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived

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[3] MPSC Case No. U-20963, 12/22/2021 Order, at 221-222.

[4] *Bluefield*, 262 U.S. at 679, 693 (1923).

[5] *Hope*, 320 U.S. at 591, 603 (1945).

risks, thereby inhibiting the Company's ability to attract capital at reasonable cost. When the Company is afforded a reasonable opportunity to earn its market-based cost of capital, a fair and reasonable balance is achieved between customers' and shareholders' interests.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk over the same period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking, requiring that the rates that are charged in any operating jurisdiction are incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. To maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Consumers Energy's electric utility operations in Michigan.

Q. Does the fact that Consumers Energy is a wholly owned subsidiary of CMS Energy Corporation, a publicly traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for Consumers Energy's electric operations, not its publicly traded parent, CMS Energy Corporation ("CMS"). More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the ability to attract capital on reasonable terms for Consumers Energy's electric operations, both on a stand-alone basis and within CMS.

Q. Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities are very important for determining the degree of regulatory support for a utility's credit quality and financial stability in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the utility operates. The direct testimony of Company witness Marc R. Bleckman describes in further detail the effect of the authorized ROE and equity ratio on credit quality as well as rating agencies' assessment of Michigan's regulatory environment.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services to customers, a utility

must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital on reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. Capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed. Although the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates, and interest rates, in the models to estimate the required return for the subject company.

Analysts and regulatory commissions recognize the importance of considering how these conditions affect the results of the cost of equity estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity

estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for the forward-looking period.

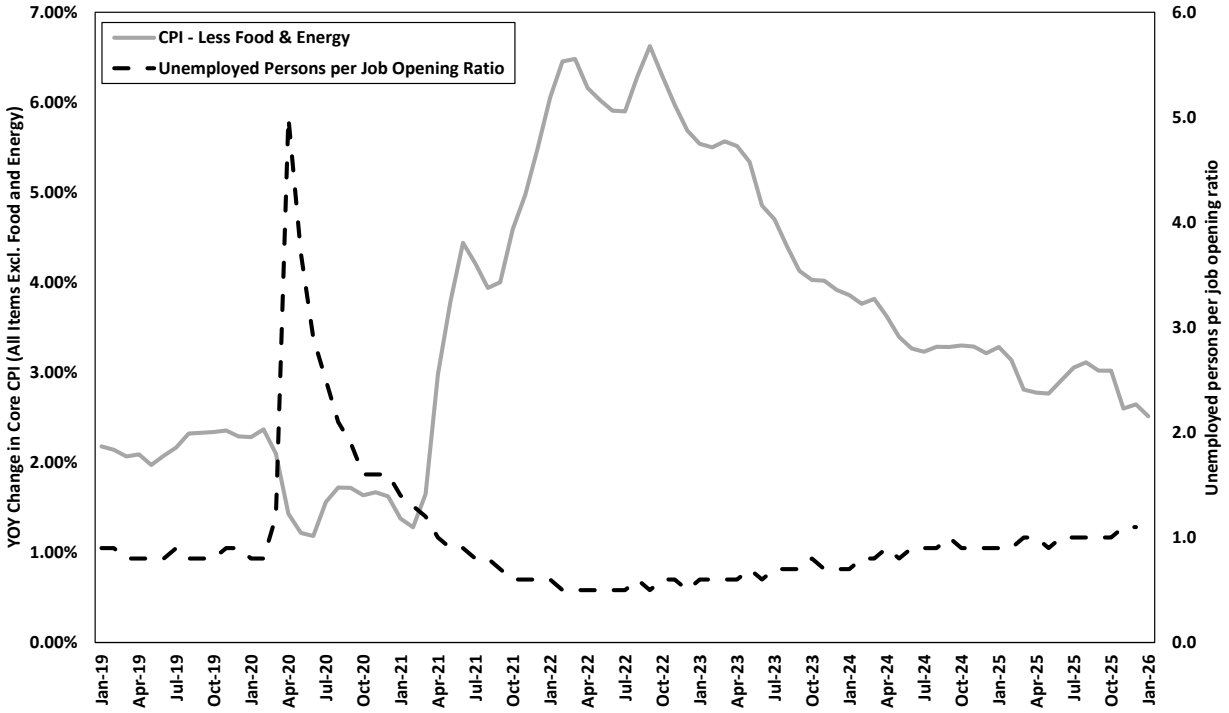
Q. What has the level of inflation been over the past few years?

A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.40% in January 2021 to a high of 6.64% in September 2022, which was the largest 12-month increase since 1982.[6] Although core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.00%.

Because the Federal Reserve's dual mandate is to promote stable prices and employment, considering employment, it is important to consider employment data in addition to inflation. The ratio of unemployed persons per job opening was 1.1 in January 2026.[7] Although the ratio of unemployed persons per job opening increased slightly in recent months, it had been consistently at or below 1.0 between April 2021 and October 2025, which suggested a tighter labor market. The strength in the labor market allowed the Federal Reserve to prioritize reducing inflation by pursuing the restrictive monetary policy needed to achieve its 2.00% target benchmark.

[6] Reade Pickert, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike," *Bloomberg,* October 13, 2022.
[7] The most recent data available at the time of this testimony; also January 2026 noted as "preliminary."

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to February 2026[8]



Q. What policy actions has the Federal Reserve taken to respond to increased inflation?

A. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25% to a range of 5.25 to 5.50%.

[8] Bureau of Labor Statistics.

Q. How have yields on long-term government bonds responded to the Federal Reserve's use of monetary policy?

A. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has increased by over 350 basis points, increasing from 1.47% on December 15, 2021 to a peak of 4.98% on October 2023. It currently remains well above 2021 levels (*i.e.*, 4.30% as of March 31, 2026).[9]

Q. Did the Federal Reserve recently reduce the federal funds rate?

A. Yes. The Federal Reserve reduced the federal funds rate by 50 basis points in September 2024, by 25 basis points in November and December 2024, and most recently by 25 basis points in September, October, and December 2025. Although the Federal Reserve kept rates unchanged through the first five meetings in 2025, its decision to reduce the federal funds rate at the final three meetings in 2025 was due to an increase in the downside risk to employment in recent months.[10]

Q. What is the expected path of monetary policy over the near-term?

A. At the January 2026 FOMC meeting, Chairman Powell noted that inflation remains "somewhat elevated" and that "while job gains have remained low, the unemployment rate has shown signs of stabilization."[11] As a result, the FOMC decided to maintain the federal funds rate range of 3.50% to 3.75%.[12] Regarding the possible path of monetary policy, Chairman Powell indicated that the reductions since September have brought the federal funds rate "within a range of plausible estimates of [the] neutral" rate and therefore, the

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9 *S&P Capital IQ Pro*.

10 Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, September 17, 2025, October 29, 2025, and December 10, 2025.

11 Federal Reserve, "Transcript of Jerome Powell's Press Conference," January 28, 2026.

12 *Id.*

Federal Reserve is well positioned to rely on incoming economic data to determine the extent and timing of any additional changes in the federal funds rate. [13] While the FOMC did not publish a forecast of the federal funds rate at the January 2026 meeting, at the December 2025 meeting, the FOMC forecasted one rate cut in 2026 and one rate cut in 2027. [14]

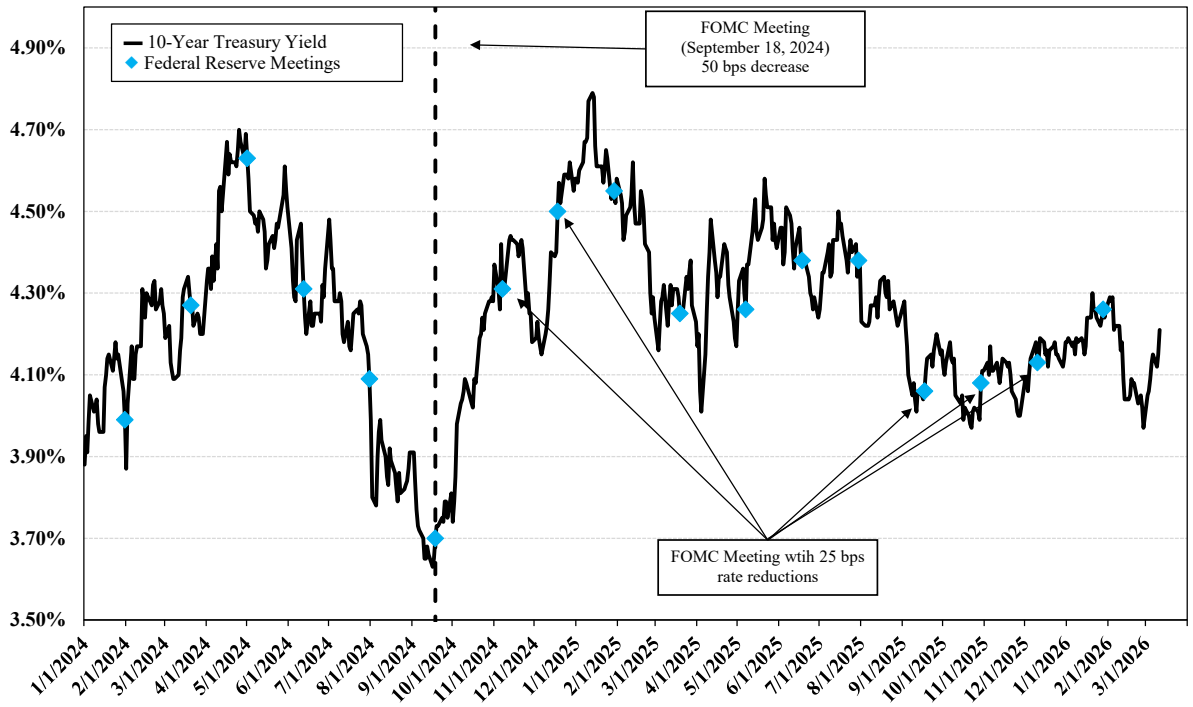
Q. What has happened to the yields on long-term government bonds since the FOMC reduced the federal funds rate in September 2024?

A. As shown in Figure 3 below, although the yield on the 10-year Treasury bond declined prior to the time of the first federal funds rate cut, the yield has generally increased since the September 2024 FOMC meeting. Further, although the yield on the 10-year Treasury bond has been volatile recently, as of March 31, 2026, the 10-year Treasury bond yield was 4.30%, which is generally consistent with the levels seen three months prior to the first reduction in the federal funds rate.

[13] *Id.*

[14] Federal Reserve, Summary of Economic Projections, December 10, 2025, at 2.

Figure 3: 10-Year Treasury Bond Yield, January 2024 through March 2026[15]



Q. Why have long-term interest rates remained above the levels at the time the Federal Reserve first reduced the federal funds rate in September 2024?

A. Ongoing policies of the current administration's economic plans have resulted in higher deficits, and persistent inflation. For example, since January 2025, the administration announced several sets of tariffs on each of the U.S.'s trading partners.[16] The implemented tariffs are largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bonds payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation which is why inflation

[15] S&P Capital IQ Pro.

[16] Jennifer Clarke, "What Are Tariffs, How Do They Work and Why Is Trump Using Them?" BBC News, August 27, 2025.

risk is greater for long-term government bonds. The significant tariff increases implemented by the current administration increase the risk that inflation will remain elevated, which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve first reduced the federal funds rate in September 2024. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields. [17]

Q. What effect does the recent Supreme Court ruling have on the tariffs implemented by the administration in 2025?

A. On February 20, 2026, the Supreme Court ruled that the tariffs implemented in 2025 under the International Emergency Economic Powers Act were illegal. However, the administration responded to the ruling by imposing a 15% tariff on all goods imported into the U.S. under Section 122 of the 1974 Trade Act,[18] which allows a President to implement global tariffs up to 15% for a period of five months after which the approval of Congress is needed for continuation of the tariffs. Therefore, the administration is still able to at least temporarily impose global tariffs, which, as noted, will continue to place upward pressure on prices.

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[17] Karishma Vanjani, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," Barron's, April 9, 2025.

[18] Dearbail Jordan, "Trump says he will increase his new global tariffs to 15%," *BBC*, February 22, 2026.

Q. Have there been any other recent developments that may affect inflation and long-term government bond yields?

A. Yes. The war in Iran and the resulting increase in underlying oil prices is expected to put upward pressure on inflation as increased oil prices not only increase gasoline prices for consumers, but also the prices of other products as well given that nearly all goods need to be transported from the place of production. The likelihood of continued elevated inflation suggests interest rates are expected to remain higher in the near term.[19]

Q. What are expectations for the yields on long-term government bonds?

A. Although the Federal Reserve's December 2025 forecast reflected additional cuts to the federal funds rate in 2026 and 2027, this was before both the referenced Supreme Court decision and the war in Iran, and economists are still expecting elevated long-term interest rates. In the most recently published report by *Blue Chip Financial Forecasts*, the consensus estimate of economists is that the 30-year treasury bond yield will remain stable at 4.80% from Q3/2026 through Q3/2027.[20] Additionally, the consensus estimate over the longer-term (*i.e.*, 2027–2031) is 4.60%.[21] Further, *Reuters* published the results of a survey of 75 bond strategists which suggests that aggressive tax and spending reforms could add over $3 trillion to the debt over the next decade. Bond strategists expect long-term bond yields to remain elevated even with the expectation that the Fed will decrease the federal funds rate because of inflation and a "resilient" economy.[22] This is important because it

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[19] *See, e.g.*, Finbar Flynn and Ruth Carson, "Bonds Lose $2.5 Trillion in Iran War Wipeout That Mirrors 2022" *Bloomberg*, March 23, 2026.

[20] *Blue Chip Financial Forecasts*, Vol. 45, No. 4, April 1, 2026, at 2.

[21] *Blue Chip Financial Forecasts*, Vol. 44, No. 12, December 1, 2025, at 14.

[22] *Reuters*, "Long Treasury yields to stay elevated as inflation, debt pressures blunt Fed easing: Reuters poll," October 14, 2025.

means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. Although the FOMC reduced the federal funds rate several times in late 2025, Chairman Powell has indicated that the Federal Reserve will continue to rely on incoming data to determine future adjustments to the federal funds rate. Further, long-term interest rates remain elevated and are expected to continue to remain elevated due to inflationary policies such as tariffs and tax cuts and the uncertainty regarding the Iran conflict and the increase in underlying energy costs. With long-term interest rates expected to remain relatively high, borrowing also remains relatively more expensive, and thus investors also demand a relatively high cost of capital, which means the cost of capital also remains relatively high.

V. PROXY GROUP SELECTION

Q. Please provide a brief profile of Consumers Energy's electric utility operations.

A. Consumers Energy is a wholly owned subsidiary of CMS. The Company provides electric service to approximately 1.9 million customers in Michigan, with approximately $5.6 billion in operating revenues from electric services.[23] As of December 31, 2025, the Company's net utility electric plant was approximately $17.9 billion. Consumers Energy currently has an investment-grade long-term rating of BBB+ from S&P Ratings ("S&P")

[23] Consumers Energy Corporation, 2025 SEC Form 10-K, December 31, 2025, at 19.

and A1 from Moody's Ratings ("Moody's").[24] On March 19, 2026, Moody's changed Consumers Energy's outlook from stable to negative citing the Company's weakening financial profile in the midst of its elevated capital investment plan.[25]

Q. Why have you used a proxy group of publicly traded companies to estimate the cost of equity for Consumers Energy?

A. In this proceeding, I am estimating the cost of equity for the Company, a rate-regulated subsidiary of CMS. Because the cost of equity is a market-based concept and the Company does not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if Consumers Energy was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company's, and thus provide a reasonable basis to estimate the appropriate cost of equity for the Company.

Q. How have you selected the companies included in your proxy group?

A. I began with the universe of companies that *Value Line Investment Survey* ("*Value Line*") classifies as Electric Utilities and have applied the following screening criteria to select publicly traded companies that:

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[24] S&P Ratings; accessed March 27, 2026. Moody's Ratings; accessed March 27, 2026.

[25] Moody's Ratings, "Moody's Ratings changes Consumers Energy's outlook to negative, affirms A1 ratings; affirms CMS Energy's Baa2 rating with stable outlook," March 19, 2026.

- pay consistent quarterly cash dividends because companies that do not pay dividends cannot be analyzed using the DCF model;
- have an investment grade long-term issuer rating;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- own generation assets included in rate base;
- derive more than 40% of total energy sales from company-owned generation;
- derive more than 60% of total operating income from regulated electric operations; and
- were not a party to a merger or transformative transaction during the analytical period considered.

Q. Did you include CMS in your proxy group?

A. No. Consistent with my general practice of excluding the subject company, or its parent holding company, from the proxy group, I exclude CMS from my proxy group for Consumers Energy.

Q. What is the composition of your proxy group?

A. The screening criteria results in a proxy group consisting of the companies shown in Figure 5, which is detailed on Exhibit A-14 (AEB-1), Schedule D-5, page 2.

Figure 4: Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the overall rate of return for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required cost of equity determined?

A. The required cost of equity is estimated using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical

techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods do you use to estimate the cost of equity for the Company in this proceeding?

A. I consider the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a BYRP analysis.

Q. Is it important to use more than one analytical approach to estimate the cost of equity?

A. Yes. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[26] suggest using the CAPM and Arbitrage

[26] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

Pricing Theory model, while Brigham and Gapenski[27] recommend the CAPM, DCF, and BYRP approaches.

Q. Has the Commission previously recognized the importance of considering the results of multiple cost of equity estimation models?

A. Yes. For example, in its order in Case No. U-21291 for DTE Gas Company, the Commission noted that the evidence that is presented by the parties in each case should be considered in determining the authorized return for the subject company. Specifically, the Commission stated:

> With respect to the ROE methodologies, the Commission finds that it is not limited to considering methodologies as approved by FERC. Specifically, the Commission agrees with the Staff that:
>
> > [t]he Commission has a history of staying agnostic on what models are presented, and hearing arguments both for and against any model on a case-by-case basis. This not only aligns well with Bluefield and Hope, which do not endorse a particular model or set of models but is paramount as many witnesses include different inputs and adjustments to their models. This flexibility in utilizing different inputs and adjustments cannot be accounted for in a system where the Commission directly prescribes the use of specific models to analysts.
>
> Staff's exceptions, pp. 8-9. The Commission agrees that the evidence presented in each case should be considered in arriving at an approved ROE for the utility. As noted in the PFD, the appropriateness of the use of the risk premium model is in flux before FERC and, at this time, the Commission declines to make a bright line rule about the applicability or appropriateness of this, or any one model as a whole. Similarly, the Commission declines to require an

[27] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

> additional analysis regarding the risk premium model in the company's next rate case as recommended by the ALJ. See, PFD, p. 209. The Commission will continue to review the evidence presented by the parties giving appropriate weight and consideration to each methodology presented on each record in each case.[28]

A. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To

[28] MPSC Case No. U-21291, Order dated November 7, 2024, at 106-107.

the extent that any of these assumptions are not objectively valid, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data do you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the 30-day, 90-day, and 180-day trading periods ended March 31, 2026.

Q. Why do you use these averaging periods?

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q. Do you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate estimate of a company's long-term projected growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Thus, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated several sources of long-term EPS growth rates into the constant growth DCF model.

Q. Which sources of long-term earnings growth rates do you use in your DCF analyses?

A. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* ("*Zacks*"); (2) *S&P Capital IQ*; and (3) *Value Line*.

Q. Have you previously relied on projected EPS growth rates provided by *Yahoo! Finance*?

A. Yes, however, *Yahoo! Finance* no longer reports consensus projected 3- to 5-year EPS growth rates. As a result, I have replaced this source with the consensus projected 3- to 5-year EPS growth rates reported by *S&P Capital IQ*.

Q. How do you calculate the range of results for the constant growth DCF models?

A. I calculate results using the average EPS growth rate from all three sources for each proxy group company. In addition, I calculate a low-end result for the constant growth DCF models using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, *S&P Capital IQ*, and *Value Line* projected EPS growth rates) for each of the proxy group companies, and use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company.

Q. What are the results of your constant growth DCF analyses?

A. The results of my constant growth DCF analyses are summarized below in Figure 5 and also presented on Exhibit A-14 (AEB-1), Schedule D-5, pages 3-5.

Figure 5: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Constant Growth DCF			
Mean Results:			
30-Day Avg. Stock Price	9.24%	10.48%	11.56%
90-Day Avg. Stock Price	9.28%	10.52%	11.61%
180-Day Avg. Stock Price	9.49%	10.74%	11.82%
Average	9.34%	10.58%	11.66%
Median Results:			
30-Day Avg. Stock Price	9.44%	10.35%	11.20%
90-Day Avg. Stock Price	9.65%	10.55%	11.16%
180-Day Avg. Stock Price	9.73%	10.62%	11.51%
Average	9.61%	10.51%	11.29%

B. CAPM and ECAPM Analyses

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[29] The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required return of an individual security

β = the beta coefficient of an individual security

[29] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

In this specification, the term (r_m – r_f) represents the market risk premium, which measures the relative riskiness of the security being evaluated. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate do you use in your CAPM analyses?

A. I use two estimates of the yield on Treasury bonds: (1) the current 30-day average yield on 30-year Treasury bonds (4.80%);[30] and (2) the projected 30-year Treasury yield for May 2026 through October 2027 (5.03%).[31]

Q. What beta coefficients do you use in your CAPM analyses?

A. As shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 6-9, I use the beta coefficients for the proxy group companies as reported by *Value Line*, which are based on five years of

[30] Bloomberg Professional, as of March 31, 2026.

[31] Bloomberg Professional. This is consistent with the source relied on by Company witness Bleckman for investors' expectations regarding future yields on long-term government bonds over the near-term.

weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 6-9, I also consider another CAPM analysis that relies on the long-term average beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2025, and which are presented in Exhibit A-14 (AEB-1), Schedule D-5, page 10.

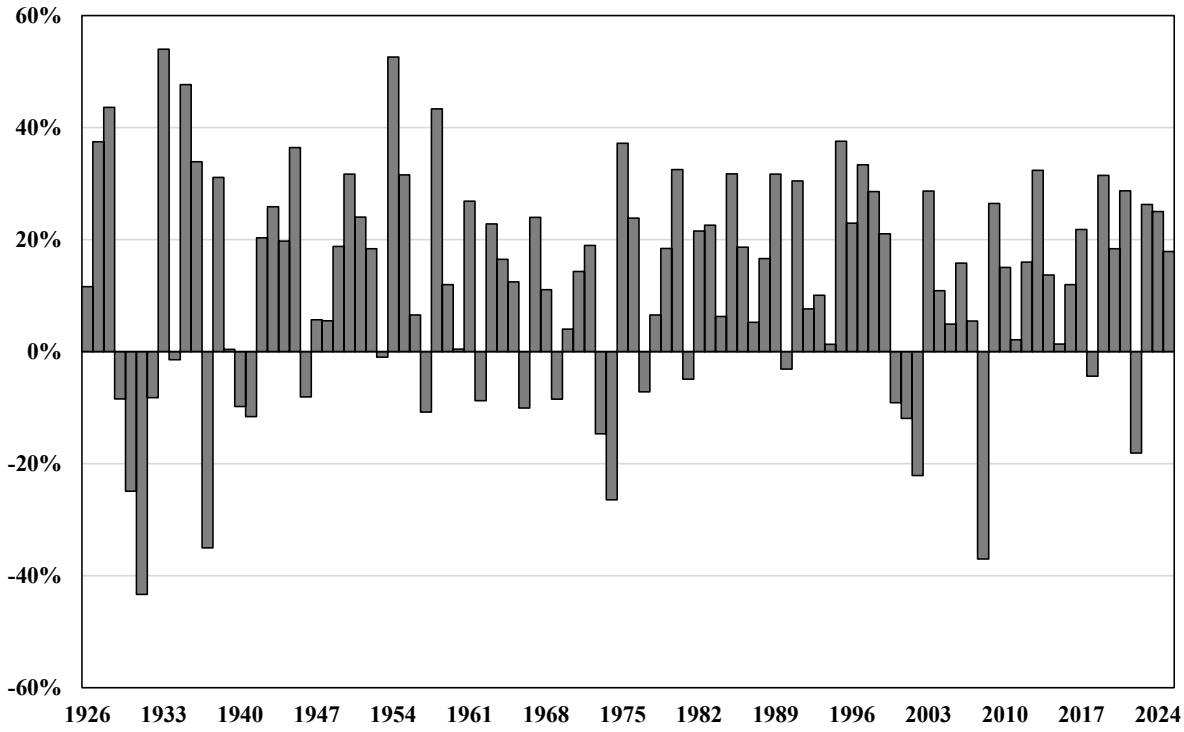
Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 11-18, the expected market return is calculated using the constant growth DCF model discussed previously in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.45% and a weighted long-term growth rate of 11.16%, the estimated required market return for the S&P 500 Index as of March 31, 2026 is 12.70%.

Q. How does the current expected market return compare to observed historical market returns?

A. As shown in Figure 6, given the range of annual equity returns that have been observed over the past century, the current expected market return is reasonable. In 53 out of the past 100 years (or 53% of observations), the realized equity market return was at least 12.70% or greater.

Figure 6: Realized U.S. Equity Market Returns (1926–2025)[32]



Q. Do you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[33] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00% to that result. The model then applies a 25.00% weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

[32] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook for 1926-2022 and from *S&P Capital IQ Pro* for 2023-2025.

[33] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

Where:

k_e = the required return of an individual security

β = the adjusted beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[34]

Consistent with the CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bond as the risk-free rate, forward-looking market return, and beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 7 below and presented in detail on Exhibit A-14 (AEB-1), Schedule D-5, pages 6-9.

[34] *Id.,* at 191.

Figure 7: CAPM and ECAPM Results

	30-Year Treasury Bond Yield	
	Current 30-Day Avg	Near-Term Projected
CAPM		
Current *Value Line* Beta	10.82%	10.88%
Long-term Avg. *Value Line* Beta	10.72%	10.78%
ECAPM		
Current *Value Line* Beta	11.29%	11.33%
Long-term Avg. *Value Line* Beta	11.22%	11.26%

C. Bond Yield Risk Premium Analysis

Q. Please describe the BYRP analysis.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Thus, risk premium approaches estimate the expected return on equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use historical authorized returns for electric utilities across the United States as the measure of the expected return on equity at that time to determine the risk premium at that time.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. Both academic literature and market evidence indicate that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important

to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 19-23 establishes that relationship using a regression of the risk premium as a function of U.S. Treasury bond yields. When the authorized ROEs serve as the measure of expected equity returns, and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[35]

Q. What does your BYRP analysis reveal?

A. As shown in Figure 8, there is a strong negative relationship between risk premia and interest rates. To estimate that relationship, I have conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

RP = risk premium (difference between authorized ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

b = slope term

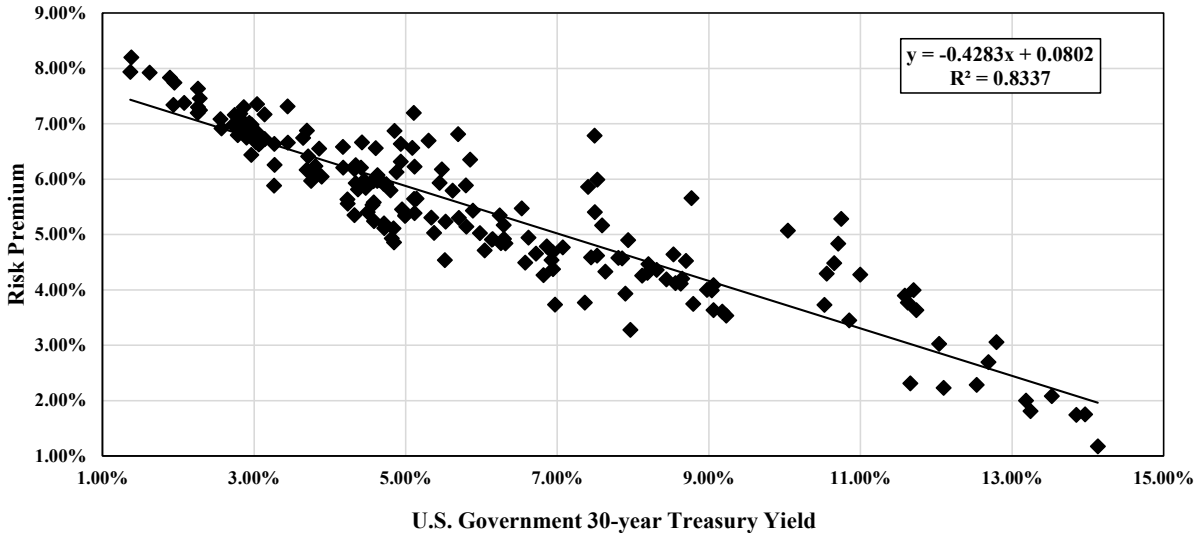
T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs is derived from all vertically integrated electric utility rate cases from January 1980 through March 2026 as reported by Regulatory

[35] *See e.g.,* S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93*," Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also,* Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholders' Required Rates of Return," *Financial Management*, Spring 1986, at 66.

Research Associates ("RRA").[36] The equation's coefficients are statistically significant at the 99.00% level.

Figure 8: Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. Figure 9 presents the results of my BYRP analysis, which is also presented in more detail on Exhibit A-14, (AEB-1), Schedule D-5, page 19.

Figure 9: BYRP Analysis Results

	30-Year Treasury Bond Yield	
	Current 30-Day Avg	Near-Term Projected
Bond Yield Risk Premium	10.76%	10.89%

[36] Authorized ROE results from limited issue rider cases, transmission-only cases, distribution cases, and cases that were silent with respect to the authorized ROE are excluded from this analysis.

VII. REGULATORY AND BUSINESS RISKS

Q. Taken alone, do the results from the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range for the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining the reasonableness of the Company's cost of equity. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Flotation Cost

Q. What are flotation costs?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q. Why is it important to consider flotation costs in the allowed ROE?

A. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the

great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny Consumers Energy the opportunity to earn its required rate of return in the future.

Q. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?

A. Yes. Suppose CMS issues stock with a value of $100, and an equity investor invests $100 in CMS in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, CMS ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. CMS invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though the investor contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q. Is the date of CMS' last issued common equity important in the determination of flotation costs?

A. No. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 24, CMS closed on equity issuances of approximately $298 million and $282 million (for a total of 55.78 million shares of common stock) in October 2004 and March 2005, respectively. The vintage of

the issuance, however, is not particularly important because the investor suffers a shortfall in every year because the investor should have a reasonable opportunity to earn a return on the full amount of capital that the investor has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which the $100 is invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q. Is the need to consider flotation costs eliminated because Consumers Energy is a wholly owned subsidiary of CMS?

A. No. Although Consumers Energy is a wholly owned subsidiary of CMS, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund the utility operations and could inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q. Is the need to consider flotation costs recognized by the academic and financial communities?

A. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit

that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[37]

Q. How have you calculated the flotation costs for CMS?

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by CMS in its two most recent common equity issuances. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 24, based on the flotation costs previously incurred by CMS, the average impact on the proxy group's cost of equity is 13 basis points (*i.e.*, 0.13%).

Q. Do your final cost of equity results include an adjustment for flotation cost recovery?

A. No. Although the final analytical results do not incorporate an explicit adjustment for flotation costs, I have considered the effect of flotation costs, along with the other risk factors present for the Company, in determining the reasonableness of the Company's proposed ROE.

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[37] Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

B. Capital Expenditures

Q. Please summarize the Company's projected capital expenditure requirements.

A. The Company currently projects capital expenditures for 2026 through 2029 of approximately $16.3 billion.[38] As of December 31, 2025, the Company had net electric utility plant of approximately $17.9 billion,[39] meaning that the Company's projected capital expenditures represent approximately 91.00% of its net electric utility plant.

Q. How do Consumers Energy's projected capital expenditures compare to those of the proxy group companies?

A. As shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 25-27, I have calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the proxy group. As shown therein, the Company's ratio of capital expenditures as a percentage of net utility plant is significantly higher than the median of the proxy group companies (*i.e.*, 2.08 times), which, all else equal, indicates a risk level for the Company that is higher than that of the proxy group companies.

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

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[38] Company provided.

[39] *Id*.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[40]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of data center growth and the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

[40] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

> Capital spending is exploding. The industry's capital spending over the past decade has been growing at a compound annual growth rate at about 6%. The industry's spending was mostly focused on safety, reliability, and energy transition, successfully reducing its greenhouse gas emissions by about 27%. To accomplish its goals, the industry has transformed its generation, increasing its reliance on renewables (about 25% of total generation) and decreasing its reliance on coal fired generation (about 15% of total generation).
>
> However, because of data center growth, we expect IOU capital spending will grow at unprecedented levels during the next decade. To maintain credit quality over this timeframe, the industry must fund these projects in a credit-supportive manner.[41]

Therefore, to the extent that the Company's rates do not continue to permit the opportunity to recover its capital investments on a regular basis, it will face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does the Company have cost recovery mechanisms in place to recover the costs associated with its capital expenditures plan between rate cases?

A. Yes. Consumers Energy does currently have recovery of certain capital expenditures between rate cases for electric distribution investment through its Investment Recovery Mechanism and for investments associated with Consumers Energy's compliance with its renewable portfolio standard through the Renewable Energy Plan ("REP"). While the Company's mechanisms provide for timely recovery of qualifying investments, Consumers Energy still depends on rate case filings for a significant portion of its capital cost recovery.

[41] S&P Global Ratings, "Industry Credit Outlook 2026, North American Regulated Utilities: Data center growth will support credit quality in 2026," January 14, 2026, at 3-4.

Q. How do the Company's existing trackers compare with the capital investment and other trackers that have been implemented by the proxy companies?

A. As shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 28-29, approximately 76% of the operating utilities of the companies in the proxy group have mechanisms for some form of capital cost recovery between rate proceedings. Because such clauses have become commonplace in utility regulation, the Company's recovery mechanisms do not reduce the Company's risk vis-à-vis that of the proxy group.

Q. Have the credit rating agencies identified risks associated with the Company's projected capital expenditures?

A. Yes. For example, as noted previously, Moody's recently revised its outlook downward for the Company from "stable" to "negative" on the basis of the risk associated with its planned capital expenditures to support load growth and meet Michigan's clean energy goal, and highlighted the importance to the Company's financial profile of supportive regulatory decisions. Specifically, Moody's stated:

> Although we view the regulatory environment in Michigan to be credit supportive, the significant step up in the company's capital investment plan without contemporaneous cost recovery through higher equity capital structure and more timely cash recovery mechanisms for large projects, will constrain the company's ability to produce credit metrics that are appropriate for its credit rating. In 2025, Consumers Energy's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio was 16.8%, excluding securitization bonds, lower than its 18% downgrade threshold primarily due to extreme storms in its service territory. Importantly, a constructive outcome on its pending rate case proceeding as well as supportive regulatory decisions on the company's

> capital investments will be critical to the company's ability to improve its financial profile.[42]

Moody's noted that a rating upgrade for the Company is not likely in the near term given the negative outlook and that a rating downgrade "would be considered if the company's CFO pre-WC to debt ratio remains below 18% on a sustained basis; or if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment, including a less constructive outcome of its pending rate case or future regulatory decisions."[43]

S&P also has acknowledged the risk associated with the Company's elevated capital investments and that an upside scenario was less likely than a downside scenario.[44] S&P noted that although the Company's recent rate case decision aligned with its base expectations, there is limited financial cushion in its financial measures compared to its downgrade thresholds.[45]

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. Although Consumers Energy has the ability to recover certain qualifying capital costs on a timely basis between rate cases, which is similar to the majority of the companies in the proxy group that also implemented capital tracking mechanisms to recover capital expenditures, the Company has the highest ratio of projected capital expenditure to net utility plant relative to the proxy group over the next five years. All else equal, this is

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42 Moody's Ratings, "Consumers Energy Company," Credit Opinion, March 23, 2026, at 1.

43 *Id*., at 2-3.

44 S&P Global Ratings, "Consumers Energy Co.'s Electric Rate Case Outcome In Line With Our Base-Case Expectations," Tear Sheet, April 29, 2026, at 2.

45 *Id*., at 1.

indicative of relatively higher risk regarding capital expenditures as compared to the proxy group.

C. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service to customers, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations, and thus require the reasonable opportunity to earn the authorized return on their invested capital to maintain their financial profiles. The Company is no exception. Therefore, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. Both Moody's and S&P consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework, and the ability to recover costs and earn returns are each given a broad rating factor of 25.00%. Therefore, Moody's assigns regulatory risk a 50.00% weighting in the overall assessment of business and financial risk for regulated utilities.[46]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[47] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2)

[46] Moody's Ratings, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.
[47] S&P Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.

tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[48]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[49] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[50]

Q. Have you analyzed the regulatory framework in Michigan relative to the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Michigan based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) the test year convention (*i.e.*, forecast vs. historical) for ratemaking; (2) the use of rate design or other mechanisms that mitigate volumetric risk and stabilize

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[48] *Id*.

[49] Moody's Ratings, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

[50] *Id*.

revenue; and (3) the ability to recover capital costs between rate cases. The results of my regulatory risk assessment are summarized as follows, and the details are shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 28-29:

> Test Year Convention: Consumers Energy uses a forecasted test year, and similarly, approximately 51% of the operating companies held by the proxy group provide service in jurisdictions that also use a fully or partially forecasted test year. Forecasted test years have been relied on in jurisdictions for many years and produce cost estimates that are more reflective of future costs which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years.
>
> Volumetric Risk: Consumers Energy does not currently have protection against volumetric risk. However, approximately 66% of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.
>
> Capital Cost Recovery: As previously discussed, Consumers Energy has recovery of certain capital investments between rate proceedings. Similarly, approximately 76% of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q. How does Regulatory Research Associates ("RRA") evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers multiple factors that affect the regulatory process including state regulatory commission decisions, the impact of actions taken by the governor, the legislature, the courts, and consumer advocacy groups, and numerous factors regarding the ratemaking environment within the jurisdiction.[51]

[51] S&P Global Market Intelligence, "RRA State Regulatory Evaluations – Energy," July 2025.

Q. Has RRA provided recent commentary regarding its regulatory ranking for Michigan?

A. Yes. RRA lowered its regulatory ranking of Michigan in August 2024 from "Above Average/3" to "Average/1," and currently notes the following:

> Regulatory Research Associates, a group within S&P Global Commodity Insights, views the regulatory climate in Michigan as somewhat constructive from an investor perspective. On July 31, 2024, RRA reduced its ranking of Michigan regulation to Average/1 from Above Average/3. RRA had placed the state on watch following a 2022 rate case decision in which the Michigan Public Service Commission (PSC) authorized DTE Electric Co. (DTE-E) an increase in rates that was less than 10% of that requested, but did not lower the ranking at that time. At the time RRA viewed the decisions to be an anomaly, as a large part of the revenue requirement difference stemmed from reliance on a higher post-COVID sales forecast than the utility had used in its revenue requirement calculations. DTE-E has now had three rate cases decided since then, which have generally been more constructive. Thus, the regulatory climate has stabilized in RRA's view. The commission has several constructive practices have been in place: a streamlined rate case process; a framework for the utilization of forecast test years to reduce regulatory lag; and a framework that permits a cash return on certain construction work in progress, thereby reducing the uncertainty of cost recovery. Retail competition for electric generation is in place but is limited, and attempts to raise this limit have not been successful. Electric utilities have retained their generation assets, and customers who do not select a competitive supplier receive service on a regulated, traditional cost-of-service basis. Adjustment mechanisms are in place for fuel costs for customers served under bundled service. However, the courts have ruled against the authorization of revenue decoupling mechanisms for electric utilities. In the gas industry, the major local distribution companies have instituted programs that allow all retail customers to choose their gas supplier, and modest small-customer switching has occurred. The gas companies utilize periodic gas cost recovery mechanisms, and the PSC has authorized revenue decoupling mechanisms for certain gas utilities. Michigan's

> regulatory and political environments continue to support significant capital investments and timely recovery of these costs. RRA now accords Michigan regulation an Average/1 ranking.[52]

Additionally, Company witness Bleckman's direct testimony provides additional detail on the credit rating agencies' assessment of Michigan's regulatory environment.

Q. What are your conclusions regarding the perceived risks related to the regulatory environment in Michigan?

A. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities generally, and have noted the importance to the Company's financial profile of supportive regulatory decisions specifically. Based on my analysis, the Company's regulatory risk, and the ability to timely recover its prudently incurred costs is slightly higher than the operating utilities of the proxy group considering that it is similar in certain respects to the proxy group companies (*i.e.*, test year convention; capital cost recovery) but does not have protection against volumetric risk and has a significantly higher proportion of capital expenditures.

VIII. CONCLUSION AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for Consumers Energy?

A. Figure 10 summarizes the results of my cost of equity analyses. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of Consumers Energy compared to the proxy group, and current and prospective conditions

[52] Regulatory Research Associates, Profile of Michigan Public Service Commission, updated March 17, 2026.

in capital markets, it is my view that the Company's requested ROE of 10.25% is reasonable and would fairly balance the interests of customers and shareholders.

Figure 10: Summary of Analytical Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Constant Growth DCF			
Mean Results:			
30-Day Avg. Stock Price	9.24%	10.48%	11.56%
90-Day Avg. Stock Price	9.28%	10.52%	11.61%
180-Day Avg. Stock Price	9.49%	10.74%	11.82%
Average	9.34%	10.58%	11.66%
Median Results:			
30-Day Avg. Stock Price	9.44%	10.35%	11.20%
90-Day Avg. Stock Price	9.65%	10.55%	11.16%
180-Day Avg. Stock Price	9.73%	10.62%	11.51%
Average	9.61%	10.51%	11.29%

	30-Year Treasury Bond Yield	
	Current 30-Day Avg	Near-Term Projected
CAPM		
Current *Value Line* Beta	10.82%	10.88%
Long-term Avg. *Value Line* Beta	10.72%	10.78%
ECAPM		
Current *Value Line* Beta	11.29%	11.33%
Long-term Avg. *Value Line* Beta	11.22%	11.26%
Bond Yield Risk Premium	10.76%	10.89%

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. Because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets

placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Consequently, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously. Company witness Bleckman's direct testimony explains the effect of the Company's authorized ROE and equity ratio on credit quality.

Q. Does this conclude your direct testimony?

A. Yes.

Ann E. Bulkley

PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 30 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in more than 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	6/25	Tucson Electric Power Company	Docket No. G-01933A-25-0103	Return on Equity
UNS Gas	11/24	UNS Gas	Docket No. G-04204A-24-0237	Return on Equity
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
California Public Utilities Commission				
Pacific Gas & Electric Company	03/25	Pacific Gas & Electric Company	25-03-010	Return on Equity
PacifiCorp, d/b/a Pacific Power	05/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	12/25	Public Service Company of Colorado	Docket No. 25AL-0499G	Return on Equity
Public Service Company of Colorado	11/25	Public Service Company of Colorado	Docket No. 25AL-0494E	Return on Equity
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	11/24	United Illuminating	Docket No. 24-10-04	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Northern Natural Gas Company	07/25	Northern Natural Gas Company	Docket No. RP25-___	Return on Equity
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	05/25	Intermountain Gas Co	C-INT-G-25-02	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/26	Peoples Gas Light & Coke Company	D-26-0065	Return on Equity
North Shore Gas Company	01/26	North Shore Gas Company	D-26-0066	Return on Equity
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	02/25	MidAmerican Energy Company	Docket No. RPU-2025-0001	Return on Equity
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	01/25	Evergy Kansas	Docket No. 25-EKCE-294-RTS	Return on Equity
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	04/25	Kentucky American Water Company	Docket No. 2025-____	Return on Equity
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	09/25	Central Maine Power	Docket No. 2025-____	Return on Equity
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Boston Gas Company	01/26	Boston Gas Company	DPU 26-50	Return on Equity
Berkshire Gas Company	11/25	Berkshire Gas Company	DPU 25-170	Return on Equity
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Consumers Energy	6/25	Consumers Energy	C-U-21870	Return on Equity
Consumers Energy	12/24	Consumers Energy	C-U-21806	Return on Equity
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Otter Tail Power Company	10/25	Otter Tail Power Company	E017/GR-25-359	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Metro Inc.	02/26	Evergy Metro Inc.	C-ER-2026-0143	Return on Equity
Ameren Missouri	09/24	Ameren Missouri	File No. GR-2024-0369	Return on Equity
Missouri American Water Company	07/24	Missouri American Water Company	WR-2024-0320	Return on Equity
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	9/25	Montana-Dakota Utilities Co.	D2025-09-072	Return on Equity
Montana-Dakota Utilities Co.	7/24	Montana-Dakota Utilities Co.	D2024-05-061	Return on Equity
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Nevada Power Company d/b/a NV Energy	02/25	Nevada Power Company d/b/a NV Energy	25-02016	Return on Equity
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
South Jersey Gas Company	11/25	South Jersey Gas Company	D-GR25110627	Return on Equity
New Jersey American Water Company, Inc.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	06/25	New York State Electric and Gas Company Rochester Gas and Electric	25-E-0375 25-G-0378 25-E-0379 25-G-0380	Return on Equity
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-342	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-341	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
Cascade Natural Gas Corporation	11/25	Cascade Natural Gas Corporation	UG 525	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/25	Pennsylvania-American Water Company	Docket No. R-2025-3057983 (water) Docket No. R-2025-3058051 (wastewater)	Return on Equity
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Co.	06/25	Otter Tail Power Co.	D-EL25-022	Return on Equity
Montana-Dakota Utilities Co.	10/23	Montana-Dakota Utilities Co.	Docket No. EL23-020	Return on Equity
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Tennessee Public Utility Commission				
Tennessee American Water Company	04/24	Tennessee American Water Company	Docket No.24-00032	Return on Equity
Texas Public Utility Commission				
Sharyland Utilities, L.L.C.	05/25	Sharyland Utilities, L.L.C.	Docket No. 57994	Return on Equity
Electric Transmission Texas LLC	02/25	Electric Transmission Texas LLC	Docket No. 57518	Return on Equity
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/25	Virginia American Water Company, Inc.	Docket No. PUR-2025-00185	Return on Equity
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/25	West Virginia American Water Company	Case No. 25-____-W-42T	Return on Equity
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wyoming Public Service Commission				
Montana-Dakota Utilities Co.	06/25	Montana-Dakota Utilities Co.	Docket No. 20004-174-ER-25	Return on Equity
Montana-Dakota Utilities Co.	10/24	Montana-Dakota Utilities Co.	Docket No. 30013-415-GR-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Thomas P. Clark, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Senior Executive Director of the Electric Supply Development & Engineering Department.

Q. Please describe your educational background.

A. I received the degree of Bachelor of Science in Engineering from Western Michigan University in 2004. Since 2010, I have been a Registered Professional Engineer in the state of Michigan. In December 2016, I received the degree of Master of Business Administration from the Ross School of Business at the University of Michigan Ann Arbor.

Q. Please describe your business experience.

A. In August 2004, I joined Consumers Energy as an Electric System Owner. In 2005, I accepted a position as an Engineer in Transactions and Resource Planning responsible for administration of the Resource Conservation Plan and the Qualified Facility Reduced Dispatch Agreements. In this role, I assisted with proposal evaluation and the administration of power purchase contracts. In early 2009, I took on responsibilities associated with the Company's Renewable Energy Plan ("RE Plan"), including the calculation of the Transfer Price associated with renewable energy and capacity and Renewable Energy Credit tracking and forecasting. In June 2013, I was assigned to the Smart Energy Department where I was responsible for the development and

implementation of demand response programs associated with the Company's deployment of Advanced Metering Infrastructure. In March 2015, I accepted the role of Manager of the Company's Resource Planning Department where I was responsible for all the Company's short-, mid-, and long-term electric generation resource planning, including the development of the Company's Integrated Resource Plans ("IRP"). In July 2017, I added Real-Time and Day-Ahead Midcontinent Independent System Operator, Inc. ("MISO") Market Operations to my Resource Planning responsibilities. In March 2021, I was promoted to Executive Director of Electric Supply where I had responsibility for purchasing and transport functions for fuel for electric generation, interaction in the MISO markets, Power Supply Cost Recovery ("PSCR") activities, wholesale settlement and transaction functions, and contract strategy functions including distribution agreements, solicitations for energy and capacity, renewable energy compliance, and distributed generation programs. In December 2021, I was assigned the role of Executive Director of Clean Energy Development with responsibility for the engineering, development, and acquisition of all Company-owned renewable energy resources, including solar, wind, and storage projects. In August of 2025, I was promoted to Senior Executive Director of Electric Supply Development & Engineering and given responsibility for engineering, development, and acquisition of all Company-owned electric supply resources.

Q. Have you previously presented testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the following cases:

- Case No. U-15675-R, the Company's 2009 PSCR Reconciliation;
- Case No. U-16300, the Company's 2009 Renewable Cost Reconciliation;
- Case No. U-16543, the Company's RE Plan Amendment;

- Case No. U-16045-R, the Company's 2010 PSCR Reconciliation;
- Case No. U-16301, the Company's 2010 Renewable Cost Reconciliation;
- Case No. U-16581, the Company's Biennial RE Plan Review;
- Case No. U-16432-R, the Company's 2011 PSCR Reconciliation;
- Case No. U-16655, the Company's 2011 Renewable Cost Reconciliation;
- Case No. U-17301, the Company's 2013 Biennial RE Plan Review;
- Case No. U-17321, the Company's 2012 Renewable Cost Reconciliation;
- Case No. U-18250, the Company's application for a financing order approving the securitization of qualified costs and related approval;
- Case No. U-18322, the Company's 2017 Electric Rate Case ("ERC");
- Case No. U-20165, the Company's 2018 IRP;
- Case No. U-20963, the Company's 2021 ERC;
- Case No. U-21090, the Company's 2021 IRP;
- Case No. U-21224, the Company's 2022 ERC;
- Case No. U-21389, the Company's 2023 ERC;
- Case No. U-21585, the Company's 2024 ERC;
- Case No. U-21816, the Company's RE Plan Amendment; and
- Case No. U-21870, the Company's 2025 ERC.

Q. What is the purpose of your direct testimony in this proceeding?

A. My testimony provides background, informational updates, and support for capital expenditures associated with new Battery Energy Storage System ("BESS") projects. Specifically, my testimony discusses two BESS projects:

- Iosco BESS Project – a 30 MW/120 MWh battery located in Oscoda Township, Iosco County, which was initially approved in Case No. U-21585, the Company's 2024 ERC. The Iosco BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP; and

- Weadock BESS Project – 45 MW/180 MWh battery located in Hampton Township, Bay County, which was initially approved in Case No. U-21585, the Company's 2024 ERC. The Weadock BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP.

Q. Please detail how your direct testimony is related to the direct testimony of other Company witnesses.

A. The capital spending associated with the Iosco BESS and Weadock BESS projects, supported by my testimony, are a subset of the overall generation capital expenditure plan explained and sponsored by Company witness Mark E. Wittbrodt, presented in Exhibit A-12 (MEW-3), Schedule B-5.2.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-46 (TPC-1)	Weadock BESS Project – Milestone Schedule;
Confidential Exhibit A-47 (TPC-2)	Weadock BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;
Confidential Exhibit A-48 (TPC-3)	Weadock BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024;
Confidential Exhibit A-49 (TPC-4)	Weadock BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024;
Confidential Exhibit A-50 (TPC-5)	Weadock BESS Project – Contract Change Order #1 to the EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated July 28, 2025;

Confidential Exhibit A-51 (TPC-6)	Weadock BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy, dated August 2, 2024;
Confidential Exhibit A-52 (TPC-7)	Weadock BESS Project – Contract Change Order #1 to the Major Procurement Contract by and between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024;
Confidential Exhibit A-53 (TPC-8)	Weadock BESS Project – Contract Change Order #2 to the Major Procurement Contract by and between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated May 13, 2025;
Confidential Exhibit A-54 (TPC-9)	Weadock BESS Project – Contract Change Order #3 to the Major Procurement Contract by and between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated September 15, 2025;
Exhibit A-55 (TPC-10)	Iosco BESS Project – Milestone Schedule;
Confidential Exhibit A-56 (TPC-11)	Iosco BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;
Confidential Exhibit A-57 (TPC-12)	Iosco BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024;
Confidential Exhibit A-58 (TPC-13)	Iosco BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024;
Confidential Exhibit A-59 (TPC-14)	Iosco BESS Project – Contract Change Order #1 EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated July 28, 2025;

Confidential Exhibit A-60 (TPC-15)	Iosco BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy Company dated August 2, 2024;
Confidential Exhibit A-61 (TPC-16)	Iosco BESS Project – Contract Change Order #1 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024;
Confidential Exhibit A-62 (TPC-17)	Iosco BESS Project – Contract Change Order #2 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated May 13, 2025; and
Confidential Exhibit A-63 (TPC-18)	Iosco BESS Project – Contract Change Order #3 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated September 15, 2025.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes. The Major Procurement Contracts for the Iosco BESS and Weadock BESS projects were negotiated by my organization and executed in the normal course of business. These contracts were executed by an officer of Consumers Energy.

IRP BESS 75 MW DEPLOYMENT PROGRAM

Q. Please provide an overview of the Company's IRP BESS 75 MW Deployment Program.

A. In Case No. U-21090, the Company's 2021 IRP, and corresponding Settlement Agreement, dated June 23, 2022, the Company agreed to add 75 MW of battery capacity between 2024 and 2027.

Q. What requirements were requested for inclusion in the Company's battery deployment program?

A. As presented in the rebuttal testimony of Company witness Richard T. Blumenstock in Case No. U-21090, the Company proposed the following requirements for its battery deployment program:

- The Company will use the battery resources included in the program in isolation or in combination with the other resource sets identified in the Proposed Course of Action (i.e., solar, Energy Waste Reduction, Demand Response);
- The battery resources, and any battery plus resource combinations, are to be owned by Consumers Energy to facilitate an expedited pace of installation and learnings;
- The Company will conduct an all-battery request for proposal ("RFP") to develop the most economic battery projects. The RFP will consider Company bid resources as well as Build Transfer Agreements and other similar arrangements;
- The battery resources will not be used to set the Public Utility Regulatory Policies Act of 1978 full avoided cost rates and therefore, will not be subject to the same competitive procurement guidelines as the IRP solicitations;
- The Company will have flexibility to procure solar plus storage options in the above discussed solicitations;
- The Company will have the flexibility to adjust amounts of annual battery deployment based upon economics of the bid proposals resulting from the RFP; and
- To the extent possible, siting of projects will be implemented in localized areas identified as providing potential benefits to the distribution systems' reliability, resiliency, and performance with a focus on vulnerable communities.

Q. What has been the Company's progress with its battery deployment program?

A. The Company conducted customer outreach, identified two specific project sites, issued two battery deployment solicitations, evaluated the proposals, executed all necessary

contracts and procurements, and began the design process for both projects. Both projects were presented in the Company's 2024 and 2025 Electric Rate Cases.

Q. Please describe the Weadock BESS Project?

A. The Weadock BESS Project is a 45 MW/180 MWh lithium-ion battery energy storage system interconnected at the Weadock Substation on the Company's 46 kV high voltage distribution system located in Essexville, Bay County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This project will be constructed on Company-owned property within the Karn/Weadock Generating complex. The project has been executed utilizing Major Procurement Agreements for Engineering, Procurement, and Construction ("EPC"); Substation Transformer Unit; and Battery Supply Agreements ("BSAs").

Q. Does this project require Board of Directors approval?

A. No. The project does not require Board of Directors approval.

Q. What is the project schedule?

A. The Weadock BESS Project is scheduled to begin commercial operation on December 21, 2026. See Exhibit A-46 (TPC-1) for further detail regarding the project schedule.

Q. Which Major Procurement Agreements has the Company executed to date?

A. The Company has executed the Substation Transformer Unit, EPC, and BSAs. Confidential Exhibit A-47 (TPC-2) and Confidential Exhibit A-48 (TPC-3) reference the Substation Transformer Agreement and associated Purchase Order with Virginia Transformer, dated March 1, 2024, and March 7, 2024, respectively. Confidential

Exhibit A-49 (TPC-4) is the EPC Agreement with Rauhorn Electric dated August 2, 2024, and Confidential Exhibit A-51 (TPC-6) is the Major Procurement contract with Our Next Energy, Inc. ("Our Next Energy") dated August 2, 2024.

Q. Have there been any significant changes to these contracts?

A. Yes. Energy Vault, Inc. ("Energy Vault") will assume the BSA previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1 (Confidential Exhibit A-52 (TPC-7) dated December 18, 2024).

Q. What necessitated the transition to Energy Vault?

A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as required under the terms of the BSA. Consequently, Our Next Energy contacted Energy Vault, a company with over 1500 MW of projects currently under development with more than 1000 MW of BESS and Hybrid Energy Storage Systems ("HESS") deployed or under construction, with the intention of having Energy Vault assume the BSA. The Company evaluated Energy Vault's financial risk and determined that they were well positioned to address the issues present with Our Next Energy.

Q. What is the projected cost of the Weadock BESS Project?

A. Table 1 below represents the Weadock BESS Project's actual and projected capital spending based on the project schedule.

Table 1: Iosco and Weadock BESS Capital Expenditure

Line No.	Description		Bridge Year	Test Year	Total Capital
		12/31/2025	16 Months Ending 4/30/2027	12 Months Ending 4/30/2028	
	(a)	(b)	(c)	(d)	(e)
1	Iosco BESS Project	$ 36.09	$ 15.14	$ -	$ 51.22
2	Weadock BESS Project	$ 48.48	$ 22.34	$ -	$ 70.82
3					
3	Total	$ 84.57	$ 37.47	$ -	$ 122.04

The Company projects that it will spend $22,340,000 in the Bridge Period, bringing the total projected capital expenditures to $70,820,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.

Q. Have the projected costs for the Weadock BESS project changed from what was presented in Case No. U-21870?

A. Yes. The total projected capital expenditures for the Weadock BESS project have increased by $3,370,000.

Q. Why have the project costs increased?

A. The increase is attributable to additional Allowance for Funds Used During Construction ("AFUDC"), updated internal loadings, and vendor-related changes discussed earlier in my testimony. In addition, delays in obtaining the Special Land Use Permit ("SLUP") from Hampton Township resulted in schedule delays that compressed the available construction window. Those delays resulted in minor increases to EPC costs under the Rauhorn Electric, Inc. construction contract, including costs associated with extended inverter storage and schedule acceleration necessary to maintain the approved construction timeline. Contract Change Order No. 1 with Rauhorn Electric, executed on July 28, 2025, revised the firm fixed contract price, updated the price breakdown and milestone payment

schedule to reflect these impacts while preserving the Commercial Operation Date. See Confidential Exhibit A-50 (TPC-5).

Q. Has the Company included any contingency in the projected capital expenditure for the project?

A. No. Company witness Wittbrodt will address the Company's position regarding contingency for Company-owned projects in his testimony.

Q. Please describe the Iosco BESS Project.

A. The Iosco BESS Project is a 30 MW/120 MWh lithium-ion battery energy storage system interconnected at the Iosco Substation on the Company's 46 kV high voltage distribution system located near the City of Oscoda, Iosco County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This project will be constructed on existing Company-owned property near the existing Iosco Substation. The project has been executed utilizing Major Procurement Agreements for EPC; Substation Transformer Unit; and BSA.

Q. Does this project require Board of Directors approval?

A. No. The project does not require Board of Directors approval.

Q. What is the project schedule?

A. The Iosco BESS Project is scheduled to begin commercial operation on December 21, 2026. See Exhibit A-55 (TPC-10) for further detail in regard to the project schedule.

Q. Which Major Procurement Agreements has the Company executed to date?

A. The Company has executed the Substation Transformer Unit, EPC, and BSA agreements. Confidential Exhibit A-56 (TPC-11) and Confidential Exhibit A-57 (TPC-12) reference the Substation Transformer Agreement and associated Purchase Order with Virginia Transformer, dated March 1, 2024, and March 7, 2024, respectively. Confidential Exhibit A-58 (TPC-13) is the EPC Agreement with Rauhorn Electric dated August 2, 2024, and Confidential Exhibit A-60 (TPC-15) is the Major Procurement Contract with Our Next Energy dated August 2, 2024.

Q. Have there been any significant changes to these contracts?

A. Yes. Energy Vault, Inc. will assume the BSA previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1, Confidential Exhibit A-61 (TPC-16), dated December 18, 2024.

Q. What necessitated the transition to Energy Vault?

A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as required under the terms of the BSA. Consequently, Our Next Energy contacted Energy Vault, a company with over 1500 MW of projects currently under development with more than 1000 MW of BESS and HESS deployed or under construction, with the intention to have Energy Vault assume the BSA. The Company evaluated Energy Vault's financial risk and determined that they were well positioned to address the issues present with Our Next Energy.

Q. What is the projected cost of the Iosco BESS Project?

A. Table 1 above provides the Iosco BESS Project's actual and projected capital spending based on the project schedule. The Company projects that it will spend $15,140,000 in the Bridge Period, bringing the total projected capital expenditures to $51,220,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.

Q. Have the projected costs for the Iosco BESS project changed from what was presented in Case No. U-21870?

A. Yes. The total projected capital expenditures for the Iosco BESS project have increased by $1,320,000.

Q. Why have the project costs increased?

A. The increase is attributable to additional AFUDC, updated internal loadings, and vendor-related changes discussed earlier in my testimony. In addition, delays in obtaining the SLUP from Oscoda Township resulted in schedule delays that compressed the available construction window. Those delays resulted in minor increases to EPC costs under the Rauhorn Electric, Inc. construction contract, including costs associated with extended inverter storage and schedule acceleration necessary to maintain the approved construction timeline. Contract Change Order No. 1 with Rauhorn Electric, Confidential Exhibit A-59 (TPC-14), executed on July 28, 2025, revised the firm fixed contract price, updated the price breakdown and milestone payment schedule to reflect these impacts while preserving the Commercial Operation Date.

Q. Has the Company included any contingency in the projected capital expenditure for the project?

A. No. Company witness Wittbrodt will address the Company's position regarding contingency for Company-owned projects in his testimony.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Laura M. Connolly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Regulated Pricing in the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Business Administration degree in Finance in December 2000 from the University of Michigan – Flint. In January 2001, I joined Consumers Energy as a Rate Analyst in the Revenue Requirements section of the Rates Department, where I held positions of increasing responsibility. I joined the Cost Analysis, Pricing and Tariff section of the Rates Department in 2012 and was promoted to Director of Rates and Regulation in July 2021.

Q. What are your responsibilities as Director of Rates and Regulation for Consumers Energy?

A. In my current role I oversee the development of the Company's Cost-of-Service Study ("COSS"), load research, rate design, and other rate-related analyses.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-12575-R	Gas Cost Recovery Reconciliation;
Case No. U-13220	Gas Cost Recovery Plan;
Case No. U-13570	Gas Cost Recovery Plan;
Case No. U-13570-R	Gas Cost Recovery Reconciliation;

Case No. U-13730	Gas General Rate Case;
Case No. U-13916	Gas Cost Recovery Plan;
Case No. U-13917-R	Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-14274-R	PSCR Reconciliation;
Case No. U-14347	Electric General Rate Case;
Case No. U-14403	Gas Cost Recovery Plan;
Case No. U-14403-R	Gas Cost Recovery Reconciliation;
Case No. U-14701-R	PSCR Reconciliation;
Case No. U-14716	Gas Cost Recovery Plan;
Case No. U-14716-R	Gas Cost Recovery Reconciliation;
Case No. U-15001-R	PSCR Reconciliation;
Case No. U-15415-R	PSCR Reconciliation;
Case No. U-15454	Gas Cost Recovery Plan;
Case No. U-15675-R	PSCR Reconciliation;
Case No. U-16045	PSCR Plan;
Case No. U-16045-R	PSCR Reconciliation;
Case No. U-16736	Energy Optimization Reconciliation;
Case No. U-16432	PSCR Plan;
Case No. U-16432-R	PSCR Reconciliation;
Case No. U-16890	PSCR Plan;
Case No. U-17197	Gas General Rate Case;
Case No. U-17281	Energy Optimization Reconciliation;
Case No. U-17601	Energy Optimization Reconciliation;
Case No. U-17688	Public Act 169 of 2014;
Case No. U-17735	Electric General Rate Case;

Case No. U-17990	Electric General Rate Case;
Case No. U-18322	Electric General Rate Case;
Case No. U-20134	Electric General Rate Case;
Case No. U-20102	Electric Tax Credit A;
Case No. U-20286	Electric Tax Credit B;
Case No. U-20563	Demand Response Reconciliation;
Case No. U-20889	Securitization of Karn Units 1 and 2;
Case No. U-20803	PSCR Reconciliation;
Case No. U-21308	Gas General Rate Case;
Case No. U-21049	PSCR Reconciliation;
Case No. U-21321	Energy Waste Reduction Plan;
Case No. U-21258	PSCR Reconciliation;
Case No. U-21424	PSCR Reconciliation;
Case No. U-21585	Electric General Rate Case;
Case No. U-21859	Ex Parte Approval of Certain Amendments to Rate GPD; and
Case No. U-21870	Electric General Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present the six cost allocation and rate design proposals as required by the Final Order in Case No. U-21859. I will also address some compliance items related to the Large Economic Development Rate ("LEDR") from the Final Order in Case No. U-21870.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-64 (LMC-1)	Summary of Large Load Proposals;

Exhibit A-65 (LMC-2)	Large Load Rate Design – Proposal 1;
Exhibit A-66 (LMC-3)	Large Load Rate Design – Proposal 2;
Exhibit A-67 (LMC-4)	Large Load Rate Design – Proposal 3;
Exhibit A-68 (LMC-5)	Large Load Rate Design – Proposal 4; and
Exhibit A-69 (LMC-6)	Large Load Rate Design – Proposal 5.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe the purpose of Case No. U-21859.

A. The Company filed an application in Case No. U-21859 to seek ex parte approval of amendments to its General Primary Demand Rate (Rate GPD) to add a Large Load provision. The purpose was to establish new tariff terms and protections for very large, energy-intensive customers to mitigate the financial and operational risks these loads pose to other customers, including the risks of stranded assets, cost shifting, and load non-materialization, while allowing Consumers Energy to serve potential large-load customers on a standardized tariff rather than through ad hoc arrangements.

Q. What did the Final Order in Case No. U-21859 require regarding cost of service and rate design proposals?

A. The Final Order in Case No. U-21859 stated the Company shall file at least six cost allocation and rate design proposals in its next rate case filed after the conclusion of Case No. U-21870 and make those proposals available to the parties in the instant case three months prior to the filing of the Company's next rate case application. MPSC Case No. U-21859, November 6, 2025 Order, page 115.

Q. What six proposals are required?

A. The required proposals were outlined in the Final Order in Case No. U-21859 as follows:

1. Traditional ratemaking as exemplified by current COSS from most recent rate order including expected full contract capacity of any large load customer(s) on Rate GPD;

2. Same as (1) but with the inclusion of a new large load customer rate class;

3. Same as (2) but using 12 Coincident Peak ("CP") to allocate costs instead of 4 CP where 4 CP is currently being utilized;

4. Current approved COSS without the large load customer(s) in service;

5. Direct assignment of costs to new large load customer rate class, including transmission, generation, and distribution costs (encompassing Contribution in Aid of Construction ("CIAC") issue); and

6. Direct assignment of costs to the individual large load customer, including transmission, generation, and distribution costs.

Q. Did the Company make the proposals available three months prior to filing in the instant case?

A. Yes, the Company made the six proposals available in the docket for Case No. U-21859 on March 2, 2026.

Q. What was the starting point for the six proposals provided in the docket for Case No. U-21859?

A. The starting point for each of the scenarios was the cost of service and rate design approved in Case No. U-21585, the Company's most recent electric rate case decided by the Commission. The Company updated the approved models to reflect changes related to the large load proposals (no new assumptions for sales of other rate classes, revenue requirements, etc. were made). The Company does not currently have any signed large load rate contracts and is not forecasting any large load in the test year of this case. Therefore, the proposals assumed a hypothetical one gigawatt ("GW") customer with a 90% load factor. The models reflect a full year of consumption at 1 GW. The Company assumed this new load would be served through a new power purchase agreement ("PPA").

For modeling purposes, the Company based the PPA pricing on the new PPA executed in 2025. The Company assumed additional transmission expense based on assumed increased load at the Company's existing transmission rates. The Company assumed no incremental increase in distribution expense as the large load customers will be required to pay for the incremental distribution investments needed to serve their new load through an upfront refundable deposit. Surcharges for demand response, electric rate case distribution deferral, and the investment recovery mechanism have been updated to include the hypothetical new sales and are included in the rate design models.

Q. How were the allocator values developed?

A. To develop the large load allocator values, the large load was assumed to be a 1 GW customer with a 90% load factor. In proposal 1, the large load volumes were included in the Rate GPD Voltage Level 1 load shape used to allocate costs to that class. In proposals 2 – 3, those volumes were included in a new large load class assumed to be served at voltage level 1. In proposal 5 where the Company direct assigns the large load costs, there is no change to the allocation of PPA or transmission costs to other customers. A set of allocators excluding large load was used to allocate these costs. However, the large load customer is allocated some shared costs including General, Common and Intangible plant, administrative and general expenses, taxes, and some working capital. In proposals 1 through 3, present revenue was calculated based on total PSCR costs and sales. Other revenue from the large load class was assumed to be equal to the large load customers' incremental PPA costs to acknowledge that the large load will be asked to pay for the incremental power supply costs. The large load other revenue was allocated across all customer classes based on their allocation of the incremental PPA costs. In proposal 5,

revenue for the large load customer was assumed to be equal to their incremental PPA and transmission costs and assigned to the large load class.

Q. How were production expenses calculated?

A. For purposes of modeling, the Company used the capacity and energy rates from the 2025 PPA as a proxy for serving new load from a hypothetical PPA. In proposals 1 and 2, where the Company is allocating costs in the traditional manner, the Company combined the incremental large load costs with existing costs and allocated the total costs using current Commission approved allocators. Capacity related PPA costs were allocated using 4 CP 75/0/25 and energy related PPA costs were allocated using a variety of energy allocators. In proposal 3, the capacity related PPA costs were allocated using 12 CP 75/0/25. In proposal 5, the incremental PPA and transmission costs were isolated from the existing PPA and transmission costs and directly assigned to the large load class.

Q. How were transmission expenses calculated?

A. Additional transmission expense was included based on the hypothetical new load applied to the existing transmission rates filed in Case No. U-21873. Actual transmission expense changes are unknown. Transmission providers bill Midcontinent Independent System Operator, Inc. ("MISO") for transmission expenses and MISO passes the costs to the Company based on our share of the Michigan Joint Zone. Those billed values are included in PSCR reconciliation filings. The Company's assignment of transmission expenses can vary based on a number of factors, including transmission upgrades needed to support the load addition, incremental transmission costs to interconnect the additional supply resources to serve the load, investments made to serve load additions made for customers outside of the Company's territory but within the Michigan Joint Zone, the Company peak

load in relation to the total Michigan Joint Zone peak load and the Company's overall share of the total Michigan Joint Zone. Given that the Company does not have any signed large load contracts and any hypothetical impacts to transmission expenses are unknown, using existing transmission rates applied to the hypothetical load provides the best estimate, at this time. The transmission costs were allocated using the approved 12 CP allocator.

Q. How were distribution expenses calculated?

A. The Company expects large load customers to pay for incremental distribution expenses to serve their load through an upfront refundable deposit. The large load customer opportunity for refund will be based on the actual gross marginal revenue. Therefore, the Company assumed no incremental distribution expense in the proposals.

Q. How were surcharges addressed?

A. The Company recalculated the Demand Response, Investment Recovery Mechanism, and Electric Rate Case Distribution Deferral surcharges based on the increased load assumptions. Changes to other surcharges will be addressed in their respective cases.

Q. What changes have been made to the models shared on March 2, 2026?

A. The Company received an order in Case No. U-21870 on March 27, 2026. This necessitated updating the March 2, 2026 filing to reflect the final cost of service and rate design models approved in the order. The Company reflected all the same assumptions outlined above in the Case No. U-21870 final cost of service and rate design models. The Company still has no planned large load additions so no other changes to assumptions were made. Company witness Emily A. Davis is sponsoring five cost of service proposals in her Exhibits A-80 (EAD-6) through Exhibit A-84 (EAD-10). The five rate design proposals are submitted as Exhibits A-65 (LMC-2) through Exhibit A-69 (LMC-6). The

Company has not presented proposal six through a separate cost of service and rate design model because it is identical to proposal five.

Q. Please describe Exhibit A-64 (LMC-1).

A. Exhibit A-64 (LMC-1) provides a side-by-side comparison of the average rate based on each proposal.

Q. What impact do these proposals have on the instant case?

A. The proposals are provided for illustrative purposes only as a requirement from Case No. U-21859. The Company has no large load sales forecasted in the test year and is not proposing to make any cost of service or rate design changes in this case related to large load customers.

Q. Please describe the compliance items related to LEDR from the Final Order in Case No. U-21870?

A. The final order in Case No. U-21870 stated that Consumers Energy shall provide a proposal for a shortened LEDR term for new customers, similar to MNSC's[1] proposal, as well as a proposal for the scenario in which the original basis for the rate approval is exhausted and there is a resulting capacity shortage.

Q. What was MNSC's proposal in Case No. U-21870 regarding contract term?

A. MNSC proposed that the LEDR contract term be shortened to seven years. They provided no basis for the seven-year term but stated that other jurisdictions have shorter term contracts. The effect of reducing the contract term is that any future customers that are interested in LEDR will sign a seven-year rate contract rather than a 15-year rate contract. The only change required for this proposal is to update the LEDR tariff to reflect seven

[1] Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan

years. The Company does not support reducing the contract term. As stated in my rebuttal testimony in Case No. U-21870, a shortened contract length could result in potential stranded assets should a customer decide to cease taking service from the Company at the end of their contract term. LEDR is available to customers using 35 MW or greater, which is a significant amount of load. This could come with significant investment costs in infrastructure to serve that load. That infrastructure could be stranded should a customer cease taking service from the Company just seven years later.

Q. How does the Company respond to the Commission's requirement to provide a proposal for the scenario in which the original basis for the rate approval is exhausted and there is a resulting capacity shortage?

A. This requirement is unclear as there was no discussion on capacity shortages in the case. The Company interprets this as a request to understand how the Company would offer LEDR if the market were experiencing a capacity shortage. The production charges for LEDR are set based on the latest forecast of MISO Cost of New Entry ("CONE"). They are updated in each rate case. A customer on LEDR locks in that production charge at the time they sign their contract. To the extent there are capacity shortages in the market, the forecast for CONE would reflect that in the form of higher prices. This would make LEDR less competitive and a new customer would be unlikely to contract for the rate.

Q. What did the Company propose in Case No. U-21870 regarding power factor for LEDR?

A. The Company proposed adding a power factor adjustment to LEDR that mirrored the design of the power factor adjustments on existing primary rates but used a higher penalty band. The Company then revised its position in rebuttal, agreeing with other intervenors

that the power factor requirements be set equivalent to other primary rates. In rebuttal, the Company asserted that there remained a concern that an extremely large customer could influence the overall power factor but that discussion was premature and would be addressed in a future filing.

Q. What does the Final Order in Case No. U-21870 state about power factor for LEDR?

A. The Commission found that a stricter power factor for LEDR customers was reasonable and ordered that Consumers "shall propose a power factor adjustment for Rate LED that is sufficient to cover the cost of power factor correction on the Company's system".

Q. How does the Company respond?

A. There is still limited data to develop this proposal. The Company does expect that larger loads, if operating at a poor power factor, result in large concentrations of vars at a single location which require more sophisticated and site-specific solutions such as Static Var Compensators ("SVCs") or Static Synchronous Compensators ("STATCOMs") However, the Company has not yet installed these advanced reactive power devices and has not conducted detailed engineering or cost studies to evaluate the capital and operation and maintenance costs associated with these technologies. The Company has gathered high-level estimates for STATCOMs from our engineering team to develop a revenue requirement on which to base a power factor charge. At an estimate of $467,554/MVar for STATCOMs, the power factor rate would be $4.45/kilovar.

Q. Is the Company proposing to apply the calculated rate of $4.45/kilovar as a credit for power factor greater than 0.875 and as a penalty for power factor of 0.700 to 0.874?

A. Not at this time. The Company proposes adding power factor requirements to LEDR equivalent to other primary rates. The Company proposes continuing to study the impacts

of power factor for these larger customers and further refine the requirements in a future case.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as the Manager of Compensation Operations for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

Q. What have your job responsibilities entailed with Consumers Energy?

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation

matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also included administering the incentive plans for CMS Energy, including Consumers Energy.

In August 2023, I took on the role of Manager of Compensation Operations. My Manager of Compensation Operations responsibilities consisted of the implementation of new and revised non-officer compensation programs, policies, and procedures for non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Manager of Compensation Operations role focuses primarily on the coordination and implementation

of the non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for non-officer programs.

In January 2024, I took on the role of Director of Compensation. My Director of Compensation responsibilities consist of the implementation of new and revised officer and non-officer compensation programs, policies, and procedures for officers and non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Director of Compensation Operations role focuses primarily on the coordination and implementation of the officer and non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for officer and non-officer programs. Lastly, the Director of Compensation consists of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. In February 2025, I returned to the Manager of Compensation Operations role which I previously held from August 2023 through December 2023.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148, U-21224, U-21308, U-21389, U-21490, U-21806, U-21870 and U-21981.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer operational goal portion of EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable; (iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW

II. EMPLOYEE COMPENSATION PHILOSOPHY

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

B. Assessment of Customer Benefits of the Incentive Compensation Plans

IV. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-70 (AMC-1) EICP Performance Measures;

Exhibit A-71 (AMC-2)	Target Pay Level Market Analysis;
Exhibit A-72 (AMC-3)	Summary of Actual and Projected – Annual Incentive O&M Expenses;
Exhibit A-73 (AMC-4)	Summary of Officer Compensation - Proxy Data for Consumers and Peer Group;
Exhibit A-74 (AMC-5)	Most Recent CMS Summary Compensation Table from the Proxy statement; and
Exhibit A-75 (AMC-6)	Allocation of Base Salary and Incentive Expense for the Historical Period.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so by using various market surveys. The practice of using multiple surveys is common practice. It allows for a broader participant pool and confirmation that the survey data is representative of market competitive wages and trends. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall total market-based competitive level and it is not in addition to it.

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that delivers base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50th percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. In this proceeding, is the Company requesting rate recovery of all Operating and Maintenance ("O&M") electric expenses related to short-term incentive compensation plans?

A. No. The Company utilizes both financial and non-financial (operational) goals in its short-term incentive compensation plan. While the Company believes that both financial and non-financial (operating) short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation linked to financial goals ($8.6 million). Included in that $8.6 million amount is the removal of the affordability (O&M savings) operational measure. This results in 25% of officer pay and 41.67% of non-officer directly linked to operational measures, with the removal of the affordability (O&M savings) operational measure.

The Company determined that the affordability measure, although included among the Company's operational goals for purposes of the EICP, is financial in nature; therefore, the Company removed the dollars attributable to that measure from the rate request in this case along with the dollars attributable to the other financial measures.

Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to non-financial (operational) goals in this rate case proceeding?

A. Yes. The Company is seeking recovery for the incentive costs associated with the operational goals portion for all officers in this case.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request in this case.

Q. Why is the Company requesting rate recovery of short-term incentive compensation operational goal expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. Competitive compensation includes base salary and short-term incentive compensation for officers and non-officers. Consumers Energy's overall compensation levels are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a less qualified workforce that would not best serve customers. According to ManpowerGroup's latest Talent Shortage survey nearly three-quarters of employers, 71% still struggle to find skilled talent. This marks a jump from a decade ago, when only 40% of employers reported such challenges. To hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries to make up for the missing incentive compensation component. Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. Incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers

Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas such as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver outcomes which result in meeting customers' expectations. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of employees who are rated as "under-performing" or "needs improvement" on their annual performance appraisals. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP incentive.

Q. How are the EICP incentives structured?

A. The EICP incentives are structured by non-officer and officer EICP. The 2025 and 2026 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2025 and 2026, there are six operational measures.); and

- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP.

The goals are the same for the officer EICP, but the weightings are different. Officers are 30% based on the achievement of operational measures and 70% based on the achievement of financial measures.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay or salary. The second part for salaried employees is annual (short-term) incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual (short-term) incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are

many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:

> Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent people to work harder and smarter, to go the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the

desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers. High-level qualitative customer benefits are listed later in my testimony. Company witness Angel L. Green's testimony illustrates the quantitative benefits to customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP are reasonable. As stated later in my testimony, it is common practice for companies to have a variable pay (i.e. EICP) component of total competitive compensation levels.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. Fourth, the Company reviews incentive compensation levels from third-party data sources to determine the target level of compensation. The fact that a portion of the compensation is in the form of an incentive

payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' compensation package or failing to meet incentive performance goals, would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for its customers. Paying competitive wages and salaries is necessary to fulfill that commitment. It would not be reasonable or fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company can attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in their leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying

at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to customers.

Q. How does the Company determine the level of compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of base pay and incentive pay is made between the Company's jobs and comparable market survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target base pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-71 (AMC-2) provides a summary of average exempt and non-exempt base pay and total cash (base pay plus target incentive) compensation for Company benchmark jobs by job family compared to market using 2025 data for 2026 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition (current employees eligible for retirement is 19% of the workforce) and have a need over

the next few years to hire engineers, information technology, and other personnel to staff various projects and serve customers. Competitive pay is necessary to retain the talent needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for engineers, as well as other personnel that are skilled, high-performing customer-focused candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being as much as or greater than 10.0% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses several third-party survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, Aon Hewitt ("Aon"), and Mercer LLC ("Mercer"), which are well-respected, independent third-party compensation experts. These surveys are conducted by surveying companies which report data on an anonymous basis. When using the survey data, the Company looks at the base pay and incentive reported for highly populated jobs for which there is a comparable job match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. By using multiple independent survey sources, the Company can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's base pay levels and the market's pay levels?

A. See Exhibit A-71 (AMC-2) for a summary of average exempt and non-exempt base pay and total cash compensation for Company benchmark jobs by job family.

Q. Does the Company attempt to keep salaries consistent with the rate of inflation?

A. No. The Company's pay levels are designed to stay consistent with the costs of labor. Labor costs and rate of inflation are not interchangeable. Cost of labor is what a particular geographic market offers as the "going rate" or compensation for its jobs. Inflation is a measure of the rate of rising prices of goods and services in an economy. Labor rates and inflation rates can change based on different factors or influences and at different rates. Labor rates follow what companies are doing to stay competitive, inflation follows economic trends which can be unrelated to how people are paid. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation. For purposes of escalating EICP labor costs for revenue requirements in this rate case, an inflation factor is used. For rate making purposes, the Company follows the direction of the Commission's December 22, 2021 Order in Case No. U-20963[1] and uses the same inflation factor to adjust both labor and non-labor expenses for determining projected labor costs. The actual merit budget, or historical merit averages, is not used.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations.

[1] See pages 244-251 for the discussion regarding inflation rates.

Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that 98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0% and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies (99%) have short-term incentive programs ("Incentive Pay Practices: Publicly Traded Companies," July 2021, WorldatWork and Compensation Advisory Partners). WorldatWork 2023 *Incentive Pay Practices* survey reports that short-term incentive continue to remain widely used among public utilities (99%). Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of energy companies utilized short-term incentive (EICP) compensation programs and indicates that short-term incentive programs are a core component of compensation in the utility sector.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,400 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP), historical rate case relief and amounts that will assist in motivating performance that will result in benefits to customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target levels are based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

Q. Did the Company reduce base pay when it started to pay incentive awards in order to obtain market-based pay based on total compensation (i.e. base pay plus incentive)?

A. No. The Company has always had a broad-based incentive compensation plan in place for management level. In 2003, an EICP for employees in former salary grades 18 and below (typically individual contributors in technical, professional, or support roles) was initiated.

Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation, which is base salary and annual incentive, was slightly below the 50th percentile (median) point of survey results. The Company targets pay levels of plus or minus 5.0% of market median. The Company's pay level, including the additional incentive, continues to be within this range.

Q. Is there an alternative to providing incentive pay for salaried employees?

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if the base target were $50,000 for a hypothetical job and market-based average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall

compensation at competitive levels through base pay plus the target incentive award amount.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests. The elimination of variable "at risk" pay would create a situation where compensation would be below market competitive levels. Competitive pay is needed to attract and retain the high-quality talent required to deliver exceptional service to customers. It would be difficult to achieve the Company's purpose of world-class performance delivering hometown service without the right talent. The knowledge, skills, and abilities of Consumers Energy's employees are key determinants in the quality and timeliness of service that customers receive. Our ability to deliver what customers expect such as reliable and safe energy delivery, on-time completion of service orders, and energy savings depends upon having the right talent in the right job at the right time. Having incentive compensation that is structured around goals that provide benefits to customers is in the best interest of the customer.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market,

as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group, which it develops based on criteria discussed below, as well as taking into account additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committees' review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committees are ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility-specific roles and comparisons of general industry roles. Where available by position, the independent executive compensation consultant of the Compensation Committees gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating

companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, relevant utility industry group, similar business mix (revenue mix between regulated and non-regulated operations), and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually, proxy-advisor service companies Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2025, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 93% in favor to approve executive compensation as described in the 2025 Proxy Statement which is above the S&P 500 average of 90%.

Q. Is survey data information for the third-party consultant proprietary information?

A. Yes. Consumers Energy's Compensation Committees engage an independent third-party consultant to provide information regarding officer compensation practices of the

Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

Q. Is the Company able to provide the survey data?

A. No. The market median information the Company utilizes is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful to have access to some market data to evaluate the reasonableness of the compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive in Exhibit A-73 (AMC-4). Exhibit A-73 (AMC-4) is the extract for the summary compensation table for the Company's most recent proxy statement.

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committees to determine compensation for Consumers Energy's top five officers. However, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top five officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committees consider the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 22 through page 24 of my testimony. Second, the data provided in Exhibit A-73 (AMC-4) is sufficiently consistent with the proprietary data that it does allow for a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation peer group.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committees of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers

Energy. The independent consultant is hired by and serves the Compensation Committees; it is not hired by or provide services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committees considers experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer's U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. This level of prevalence still exists based on a 2021 World at Work survey with 99% of publicly traded companies providing annual incentives to executives. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

Q. Please describe the EICP that was in place for 2025.

A. The EICP for 2025 was based on achieving performance goals related to critical areas of the Company's operations. The goals focused on continuous improvement measures and maintaining financial health to deliver value benefits to customers (not seeking recovery of financial goals in this case). The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to customers, and to do so safely. Each year, the Company establishes utility-specific performance criteria which

focus on continuous improvement goals and breakthrough goals. For 2025, there were six specific operational performance measures, and one measure related to being financially healthy. The EICP Operational Performance Measures are summarized on Exhibit A-70 (AMC-1). The 2025 officer and non-officer goals and weighting are shown on page 1 and operational goal targets on page 2.

Q. Please describe Exhibit A-70 (AMC-1).

A. Exhibit A-70 (AMC-1) identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2025 historical year, 50.0% of the non-officer incentive compensation and 30% of officer incentive compensation were based on operational performance. For purposes of this rate case, the Affordability (O&M savings from Waste Elimination) measure associated cost has been removed from the rate request as the Company has determined that it is financial in nature.

Q. Is the structure of the EICP goals for 2026 similar to 2025?

A. The specific performance measures and targets for 2026 are, as in prior years, a combination of measures related to operational performance and financial performance. As indicated above, the Company is not seeking recovery of the financial performance measures in the case. For non-officers, the operational performance and financial health goals will be weighted equally (50% operational and 50% financial). For officers, the operational performance and financial performance measures are weighted 30% operational and 70% financial. The officer operational goals are the same as the non-officer operational goals.

Q. Will the non-officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational goals may vary from the historical test year, areas of focus will continue to include safety, reliability, cost, delivery, and customer care.

Q. Will the officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Operational and financial performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance (same goals as non-officers) and the remaining 70% is based on financial performance. As noted above, the Company is not seeking recovery of the financial performance measure in this case.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness Green provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

Q. Were there any incentive plan changes in the historical test year or planned changes to the future years?

A. There were no plan changes to the EICP for officers and non-officers in 2026 or plans to make any changes for 2026 or 2027.

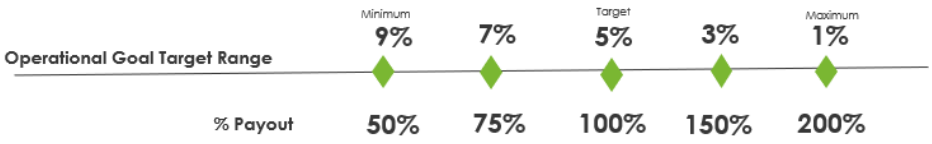
Q. How are the payout levels that are shown on Exhibit A-70 (AMC-1) set?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Are the payout levels that are shown on Exhibit A-70 (AMC-1) similar to 2025 and the projected test year?

A. Yes, each operational measure will have its own threshold, target, and maximum for payout. This practice aligns better with market practice and with engaging and motivating performance. Gallup research supports substantial and well-established connections between employee engagement and the achievement of outcomes critical to the business and to customers. See illustration of banded goals below:

Example (Illustration Only):



This structure was in place for 2025 and planned to be in place for the projected test year.

Q. Why are you including both gas and electric performance measures in this plan as this is a electric rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures. EICP eligibility or expense is not broken down by which employees support the electric or gas operations or a combination.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards were based on the achievement of EPS and utility operational goals for the historical test year. As indicated above, the officer plan has a 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer performance while aligning with typical indicators of officer strategy execution through financial goals (weighted at 70%) and corresponding higher weighting.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committees determine the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committees consider the following factors:

- The target incentive level and actual incentives paid in recent years;
- The relative importance, in any given year, of each performance goal established; and

- The advice of the Compensation Committees' compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. Assessment of Customer Benefits of the Incentive Compensation Plans

Q. What level of expenses for Consumers Energy's incentive plans have been included in the test year revenue requirement?

A. The Company is requesting recovery of electric O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The following is a listing of the goals illustrated in Exhibit A-71 (AMC-2) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
  (Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
  (Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience** - Cxi
  (Survey measuring Customer Experience)
- **Electric Reliability** - SAIDI
  (System Average Interruption Duration Index)
- **Methane Emission Reduction**
  (Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately $1.1 million as illustrated in Exhibit A-72 (AMC-3).

Q. Please explain Exhibit A-72 (AMC-3), page 2.

A. Exhibit A-72 (AMC-3), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate to historical O&M expense. Page 2, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation was applied to. Columns (e) and (g) show the amounts to which an inflation rate increase were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that

were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). For purposes of incentive expense, labor increase uses an inflation rate applicable. No merit or labor rate was applied.

Q. How are the electric expenses of $2.3 million related to annual incentive compensation calculated?

A. The $2.3 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on salaries multiplied by the approved target incentive percentage of salary from the Compensation & Human Resources Committees of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense), forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each career stream and job level multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the electric portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting department.

Q. What is the allocation percentage of EICP expense to electric operations?

A. The allocation percentages between electric and gas operations for EICP are supplied by the accounting department. All officers and non-officer EICP is allocated between electric and gas based on Consumers Energy's historical labor allocation study from the previous year as described in Exhibit A-75 (AMC-6). The allocation is based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating

revenue; (iv) headcount; and (v) labor. Only the electric portion of the EICP expense is being requested in this case. The percentage allocation to electric operations is as follows:

- non-officer is 62%, and
- officer is 64%.

Q. Is a portion of the electric incentive compensation expense allocated between O&M and capital?

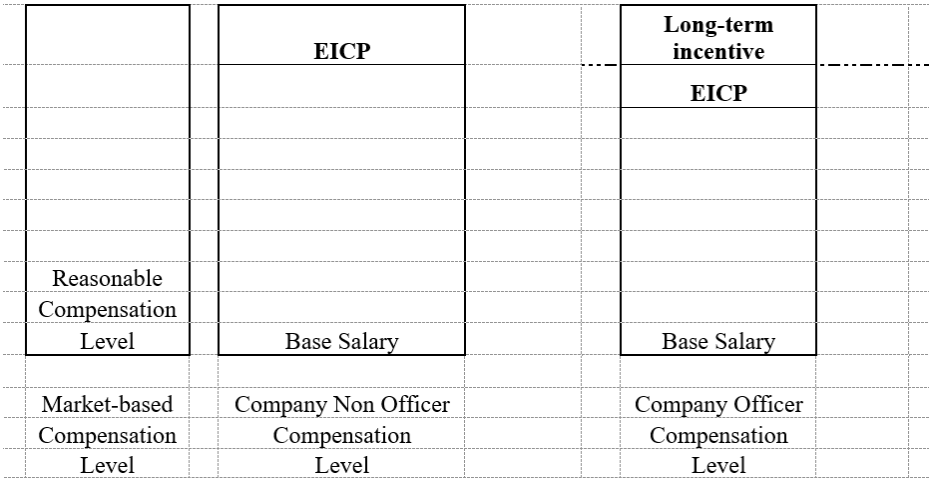
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015, approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor percentages charge between O&M and capital is based on labor studies performed by each business unit for the operational goals portion of the cost. Costs associated with financial performance measures are charged to O&M only.

Q. Do Consumers Energy's electric customers benefit from making a portion of employee compensation subject to incentives?

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for their position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to

benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the financial performance measures' cost. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance and for financial measures. If actual payouts in future years are less than target levels due to under performance, then the Company's shareholders will absorb the consequence of underperformance results along with customers. The Company is allocating to shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve

customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2025, the unemployment rate was 5.0% in Michigan and 4.4% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and the Company must offer a compelling value proposition to attract and retain the talent required to realize our Company purpose of world-class performance delivering hometown service.

Q. Is the EICP a bonus or profit-sharing plan?

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit-sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company must re-earn the incentive award every year. If performance goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Green in her direct testimony in this case.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately $2.3 million for the test year. The quantifiable electric benefits illustrated in Company witness Green's direct testimony and exhibits are greater than $10 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. CONCLUSION

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost

above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $2.3 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of operational goal incentive compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;
- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;
- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;
- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;
- The plan incorporates operational as well as financial performance goals;
- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;

- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and

- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

EMILY A. DAVIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Emily A. Davis, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst in the Rates and Regulation Department.

Q. Please describe your educational background and experience.

A. In May 2008, I graduated summa cum laude from Illinois State University with a Bachelor of Science Degree in Economics and a minor in Business Administration. In 2010 I received a Master of Science Degree in Applied Economics with a specialization in Electricity, Natural Gas, and Telecommunications. I joined Consumers Energy as a Senior Rate Analyst in March 2018 and was promoted to my current position in September 2023. Before joining Consumers Energy I held various positions with Nicor Gas and its parent companies including Rate Analyst, Strategic Planning Consultant, and Manager of Regulatory Affairs.

Q. What are your responsibilities as a Principal Rate Analyst for Consumers Energy?

A. I am responsible for conducting analyses in support of the Company's Cost of Service Studies ("COSS") and developing testimony and exhibits in support of proposals in regulatory proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously provided testimony before the Commission?

A. Yes. I have filed testimony on behalf of the Company in the following cases:

Case No. U-21870 Electric General Rate Case, Cost-of-Service;

Case No. U-21389 Electric General Rate Case, Cost-of-Service;

Case No. U-21224	Electric General Rate Case, Cost-of-Service;
Case No. U-20963	Electric General Rate Case, Cost-of-Service;
Case No. U-20650	Gas General Rate Case, Cost-of-Service;
Case No. U-20322	Gas General Rate Case, Cost-of-Service;
Case No. U-20287	Federal Tax Cut and Jobs Act Tax Credit B (Gas);
Case No. U-20103	Federal Tax Cut and Jobs Act Tax Credit A (Gas); and
Case No. U-20102	Federal Tax Cut and Jobs Act Tax Credit A (Electric).

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to sponsor the Company's electric COSS for the forecasted 12-month period ending April 30, 2028 ("test year") and related proposals. Those proposals include the calculation of the State Reliability Mechanism ("SRM") charge and Substation Ownership Credit ("SOC") as well as the allocation of the Electric Rate Case Deferral and Investment Recovery Mechanism ("IRM") surcharges. I also address various Commission compliance requirements involving the COSS from prior orders.

Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?

A. No.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (EAD-1)	Schedule F-1	Electric COSS- Projected 12-Month Period Ending April 30, 2028;
Exhibit A-76 (EAD-2)		Alternative Meter Allocation;
Exhibit A-77 (EAD-3)		SRM Calculation;

Exhibit A-78 (EAD-4)	SOC Calculation;
Exhibit A-79 (EAD-5)	Allocation of Surcharges;
Exhibit A-80 (EAD-6)	Large Load COSS- Proposal 1;
Exhibit A-81 (EAD-7)	Large Load COSS- Proposal 2;
Exhibit A-82 (EAD-8)	Large Load COSS- Proposal 3;
Exhibit A-83 (EAD-9)	Large Load COSS- Proposal 4; and
Exhibit A-84 (EAD-10)	Large Load COSS- Proposal 5.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

II. TEST YEAR ELECTRIC COSS

III. COSS COMPLIANCE ITEMS

IV. SRM CALCULATION

V. SOC CALCULATION

VI. ALLOCATION OF SURCHARGES

VII. SUMMARY OF PROPOSALS

I. COST OF SERVICE OVERVIEW

Q. What is a COSS?

A. A COSS is a three-part analysis that quantifies the utility's embedded cost of serving various customer classes. The information provided by the COSS is used to guide the design and development of customer rates.

Q. What are the three parts or steps involved in performing a COSS?

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that the cost is incurred to provide/support. Consumers Energy's electric functional cost categories are production and distribution. Cost classification involves categorizing costs as demand, customer, or energy related according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. When possible, individual costs that can be traced to a class of customers may be directly assigned to that class. The fundamental principle guiding the assignment of costs in the COSS is cost causation; in other words, the costs assigned to a class or group of customers should reflect how those customers drive or influence the utility's costs. This process is relatively standard across the utility industry and is supported by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Rate Design Manual.

Q. What are the allocation factors and how were they developed?

A. There are 18 input allocation factors (or schedules) and 59 calculated allocation factors that were derived (at least in part) from the input schedules. Each schedule was developed to allocate to each customer class its utilization of a particular part of the electric system. The schedule numbers are shown in Exhibit A-16 (EAD-1), Schedule F-1, pages 7 through 12. The allocation factors, expressed as percentages, were applied to the COSS cost line items to calculate class cost responsibility.

Of the 18 input allocation schedules, nine (schedules 100-108) are based on energy use measured at different times, seasons, and in total. Three schedules are based on measures of demand including Coincident Peak ("CP") (120 and 121) and Class Peak (127). The remaining schedules (141 through 143, 150, 160, and 170) were developed using test year revenue (141 through 143), sales (150) and customer count (160 and 170) data supplied by Company witnesses Eugene M. Breuring and Michael C. Grondin. The calculated allocation schedules were derived from the input schedules, other categories of assigned costs and/or other information contained within the COSS.

Q. How were the energy and demand allocation schedules developed?

A. A three-year average of historic load profiles (2022, 2023, and 2024) was used to develop an average test year profile for each customer class. The loss factors sponsored by Company witness Emily M. Duke were applied to the average test year profile to arrive at generation level usage which was used to develop the allocation schedules.

Q. How were the historic load profiles developed?

A. The Company utilized an external consultant to develop the historic load profiles. The consultant used load research software to arrive at a total class profile using the Company's meter data for each customer class. Depending on the rate, either a sample or all available meter and billing data was utilized to develop the load profiles. Load profiles for street lighting were assumed to follow daylight hours and the profiles for unmetered usage were assumed to be a flat average use per hour.

II. TEST YEAR ELECTRIC COSS – VERSION 1

Q. Please describe Exhibit A-16 (EAD-1), Schedule F-1.

A. Exhibit A-16 (EAD-1), Schedule F-1, is a 28-page exhibit that contains the results of the COSS that is being used to design rates.

Q. How is Exhibit A-16 (EAD-1), Schedule F-1, organized?

A. A summary of the COSS results can be found on pages 1 through 3 of Exhibit A-16 (EAD-1), Schedule F-1. The revenue deficiency/(sufficiency) is shown on line 21 with the total revenue requirement and amount to be collected in base rates ("Proposed Rate Design Revenue" or "PRDR") on lines 22 and 24 respectively. Lines 25 through 29 break out the PRDR by function and other categories that are used by rate design. Additional rate base and Operating and Maintenance ("O&M") detail can be found on pages 4 through 6 and a list of the allocation schedules can be found on pages 7 through 12. Pages 13 through 28 include the cost line item detail and assigned allocation factors required by the Schedule F-1 template included in the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Please provide an overview of the allocation factors by cost category, last approved by the Commission in Case No. U-21870, that were relied on in the COSS.

A. Production capacity costs were assigned to customers using allocator 220 which weights demand (the highest four CPs) by 75% and total energy by 25% ("4CP 75/0/25"). Production non-capacity costs were allocated on energy use for the associated time periods and seasons. Transmission expense was allocated on 12CP demand ("12CP 100"). Distribution plant was primarily allocated on Class Peak demand[1] with related costs

[1] Meter facilities and services are assigned using allocators based on the number of customers.

allocated in a similar manner as the associated plant. General, Common, and Intangible ("GC&I") plant and related costs were allocated on labor. Working capital was primarily allocated on revenue, plant in service, and labor. Customer related and administrative & general expenses were primarily allocated on customer, revenue, and labor allocators. Property tax was allocated in a similar manner as the associated plant and income tax was primarily allocated on pretax net operating income.

Q. What updates were made to Exhibit A-16 (EAD-1), Schedule F-1?

A. The Company made routine updates for historic and test year data including updates to the allocation schedules discussed in Section I of my direct testimony. Where new or additional cost detail was provided, those costs were treated in a manner consistent with current approved methodologies and/or allocated using a method described below.

Q. How does Exhibit A-16 (EAD-1), Schedule F-1 treat the storm deferral amortization expense discussed by Company witness Hannah L. Patton?

A. The amortization expense, which predominantly includes Low Voltage Distribution ("LVD") Overhead ("OH") O&M expenses, is functionalized as distribution and allocated using Allocator 320 ("PIS-LVD OH Lines & Services"). This is consistent with how the Company allocates LVD OH O&M expenses in the Commission approved COSS.

Q. Please summarize the COSS results from Exhibit A-16 (EAD-1), Schedule F-1.

A. To collect the $455.8M revenue deficiency calculated by Company witness Patton, the Company's COSS increases proposed revenues (e.g. PRDR) by 10.9% for the Residential class, 8.6% for Commercial Secondary, 11.1% for Lighting & Unmetered and 8.3% for Primary. These results are summarized in Table 1 below.

Table 1: Summary of COSS Impacts by Class ($ in millions)				
Description	**Residential**	**Commercial Secondary**	**Lighting**	**Primary**
Present Revenue	$2,504.3	$1,163.8	$44.2	$936.8
Version 1	272.9	100.1	4.9	78.0
Total PRDR	**$2,777.2**	**$1,263.9**	**$49.1**	**$1,014.8**
	10.9%	**8.6%**	**11.1%**	**8.3%**

III. COSS COMPLIANCE ITEMS

Q. What COSS analyses and/or support is being provided to comply with previous Commission Orders?

A. To comply with the Commission's Order in Case No. U-21859, the Company is providing five COSS exhibits (Exhibit A-XX (EAD-6) through A-XX (EAD-10)) that reflect Case No. U-21870 approved costs and COSS methodologies and include the large load proposals ordered by the Commission. Company witness Laura M. Connolly discusses the Company's large load proposals, assumptions, and results in greater detail in her testimony.

In addition, the Commission's Order in Case No. U-21870 included two COSS-related requirements involving Advanced Metering Infrastructure ("AMI") meter cost allocation and empirical data on bidirectional power flow to be addressed in the Company's next rate case.

A. AMI COST ALLOCATION

Q. Please elaborate on the Commission's directive on AMI meter cost allocation in Case No. U-21870.

A. On pages 379-381 of the Final Order the Commission stated that it found merit in MNSC's[2] argument that AMI meters provide benefits beyond metering that should be considered in

[2] Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan

the allocation of those costs but took issue with the disproportionate result of MNSC's proposed alternative. The Commission ordered the Company to propose an alternative allocation in its next electric rate case that reflects the benefits provided by AMI meters. The COSS results using the alternative meter allocator (171) developed by the Company are provided in Exhibit A-76 (EAD-2).

Q. How did the Company develop the alternative meter allocator?

A. The Company's alternative meter allocator builds on the conceptual framework offered by MNSC witness Caroline Palmer in Case No. U-21870. Specifically, that AMI meters provide additional benefits compared to "traditional" non-AMI meters and those benefits are 36% energy, 17% demand, and 47% customer related. One of the flaws in MNSC's approach was that Ms. Palmer divided the entire AMI meter cost amongst these additional benefits without considering or comparing the cost of a non-AMI meter to calculate the AMI "premium" incurred to realize those benefits. To fix this issue, the Company calculated the AMI premium by comparing the cost of a standard single phase AMI meter with a single phase non-transmitting meter. The total AMI premium was calculated by multiplying the cost difference by the number of AMI meters. The resulting AMI premium was allocated using the energy, demand and customer weightings proposed by MNSC. The Company used total energy (100) to allocate energy-related costs, the production capacity allocator (220) to allocate demand costs, and the customer allocator (160) to allocate customer costs. The remaining meter costs (non-AMI premium) were allocated to customers using the existing weighted customer allocator 170.

Q. What impact does the alternative meter allocator have on the COSS results?

A. Using the alternative meter allocator increases the cost of service by $0.7 million (less than 0.1%) for the Residential class, $0.9 million (0.1%) for Primary and $0.1 million (0.1%) for Lighting & Unmetered. The Commercial Secondary cost of service decreases by $1.7 million (0.1%).

Q. Is the Company proposing that the Commission adopt the alternative meter allocator?

A. No. While the Company's proposal is an improvement over what MNSC offered in Case No. U-21870, the Company continues to support using the current weighted customer allocator (170).

First, the Company believes the weighted customer allocator appropriately reflects cost causation by taking into account both the number of customers and the cost of the meter which are generally more expensive for larger non-residential customers. While the Company agrees that AMI meters provide several benefits, the existence of other benefits does not change the fact that the addition of a customer requires a meter to connect and serve that customer which is what ultimately drives meter costs.

In addition, updating the alternative meter allocator will become more challenging in the future as many vendors no longer offer non-transmitting meters. AMI meters have become the new standard.

Finally, the reasonableness of the current meter allocator is evidenced by the fact that the results of the alternative meter allocator do not materially alter the COSS results.

B. BIDIRECTIONAL POWER FLOW

Q. Is the Company providing empirical data on bidirectional power flow in response to the Commission's directive in Case No. U-21870?

A. Yes. Company witness Kurt K. LaFrance provides the Company's empirical analysis and findings.

Q. Do the findings from that analysis change the Company's proposed COSS allocation?

A. No. As stated by Company witness LaFrance, the extent of bidirectional power flow occurring between the LVD and High Voltage Distribution ("HVD") system is de minimis. In 2025 only 0.21% of total MWh flowed in the reverse direction from the LVD Primary to the HVD system. Out of the Company's 914 distribution substation transformers with Distribution Supervisory Control and Data Acquisition ("DSCADA") only three experienced reverse power flow levels at or above 50% in 2025 and two of those are paid exclusively by LVD customers. Mr. LaFrance further explains that the Company does not make HVD investment decisions based on bidirectional flow from the LVD system.

To evaluate the materiality of the COSS impact if the substations housing the two identified transformers were re-allocated across all customers, the Company calculated a high-level revenue requirement for the associated substation plant. Then, those costs were re-allocated to customers using the percentage of reverse power flow; for example, if reverse power flow at a substation was 60%, then 60% of that substation cost was allocated to all customers. The results of that analysis show that LVD customers currently pay $0.1 million for those two substations. Allocating those costs across both HVD and LVD customers would reduce Residential Class costs by less than $0.01 million.

The analysis provided by Mr. LaFrance and the findings above on the COSS impact supports the Company's position that bidirectional power flow is currently not happening at significant enough levels to merit changes in how the Company allocates costs.

Q. Do the findings from the bidirectional flow analysis change the Company's proposed battery COSS allocation?

A. No. The batteries that the Company categorizes as distribution and are connected to the LVD system were deployed in lieu of other distribution system upgrades and/or equipment such that the Company believes it is appropriate to allocate those costs in the same manner as that distribution equipment. The substation transformers that serve the distribution batteries measured no reverse power flow in 2025.

In addition, from a materiality standpoint, the impact of distribution batteries on the overall COSS is small; the return on and of distribution battery plant in the COSS is less than $0.5 million. If that amount was allocated across all customer classes residential costs would decrease by less than $0.03 million.

IV. SRM CALCULATION

Q. Please describe Exhibit A-77 (EAD-3).

A. Exhibit A-77 (EAD-3) shows the calculation of the SRM charge. In compliance with the Commission's most recent Order in Case No. U-21870, the SRM calculation no longer includes the reconciliation outlined in a previous Commission Order (Case No. U-21585). To arrive at the SRM charge, non-capacity related costs (line 9) are subtracted from total production costs (line 1) to arrive at total capacity-related costs (line 10). Projected revenue (line 16) less associated fuel cost (line 17) is subtracted from the total capacity-related costs (line 10) to arrive at the net capacity cost (line 19). The net capacity cost is divided by the

demand provided by Company witness Joshua W. Hahn (line 20) to arrive at the SRM charge of $201.84/MW-Day.

The total non-capacity related cost (line 9), total revenue less fuel cost (line 18), and net capacity cost (line 19) from Exhibit A-77 (EAD-3), are the same values that appear on lines 25 through 27 of Exhibit A-16 (EAD-1), Schedule F-1.

V. SOC CALCULATION

Q. Please describe Exhibit A-78 (EAD-4).

A. Exhibit A-78 (EAD-4) provides the calculation of the SOC given to customers who own their own substations. The calculation takes the substation costs that have been allocated to Rates GPD, GPTU, and EIP customers on Voltage 1 and Voltage 2 and determines the cost on a per kW basis for each voltage level.

Lines 1 through 5 in Exhibit A-78 (EAD-4) list items included in the substation rate base, with the total substation rate base in line 6. The substation rate base is multiplied by the pre-tax return rate in line 7 to arrive at the pre-tax return in dollars in line 8. Various expenses (lines 9 through 11) and revenue credits (line 12) are added to the pre-tax return to arrive at the total substation revenue requirement by voltage on line 13. This total (in thousands of dollars) is divided by the maximum demand in MW (line 14) from Company witness Grondin to determine the SOC on line 15.

VI. ALLOCATION OF SURCHARGES

Q. Please describe Exhibit A-79 (EAD-5).

A. Exhibit A-79 (EAD-5) shows the allocation, by rate class, for the Electric Rate Case Deferral surcharge sponsored by Company witness Patton, and the IRM surcharge

sponsored by Company witness Heidi J. Myers. Exhibit A-79 (EAD-5) is used by Company witness Grondin to calculate the surcharge rates.

Q. How is the Company proposing to allocate the Electric Rate Case Deferral and IRM surcharges?

A. The Company is proposing to allocate these surcharges, which include the cost of various investments in the Company's distribution system, to each class in proportion to their share of total distribution costs in this case. This is the same method that has been approved by the Commission in previous cases.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

JEFFREY P. DICKEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey P. Dickey, and my business address is 4000 Clay Ave, Grand Rapids, Michigan 49548.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Emergency Preparedness.

Q. Please describe your educational background and work experience.

A. I have an Associates degree in Business Administration from Grand Rapids Community College. I started at Consumers Energy as a meter reader. Through career progression in the Company's engineering, emergency management, and electric operations departments, I currently serve as the Executive Director of Emergency Preparedness, with responsibility for preparedness, emergency management and response activities, and teams. I have been directly involved in service restoration activities for my entire career at Consumers Energy. I have fulfilled nearly all back office and leadership roles within the storm Incident Command System (ICS) along with in the field roles including mutual assistance. Today, I am leading the Company's initiatives to improve service restoration activities.

Q. What are your responsibilities as Executive Director of Emergency Preparedness?

A. I am responsible for leading the Emergency Preparedness and Response organization.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's projected and deferred service restoration spending, including the facility upgrades and enhancements as part of the Dispatch/Control Center Consolidation project as well as the deferred operating and maintenance ("O&M") expenses from the 2025 March/April ice storm. The bridge period is defined as January 1, 2026, through April 30, 2027. The test year is defined as May 1, 2027, through April 30, 2028. In the test year, the Company projects $192.6 million in service restoration O&M expense, which is based on the Company's actual 2025 Service Restoration expense, with costs for the March/April ice storms of 2025 removed. The projected service restoration O&M total was then adjusted for inflation throughout the test year period. The projected expense is detailed further in the Service Restoration Test Year O&M Expense section beginning on page 20.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-85 (JPD-1)	March/April Ice Storm Comprehensive Cost & Comparative Analysis Data.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SERVICE RESTORATION OVERVIEW AND IMPROVEMENTS

II. U-21914 STORM DEFERRAL REQUIREMENTS

III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

IV. DIGITAL AND PROCESS ENHANCEMENTS

V. CONTROL/DISPATCH CENTER CONSOLIDATION

VI. SUMMARY

I. SERVICE RESTORATION OVERVIEW

Q. How does the Company's service restoration program benefit customers?

A. When electrical service is interrupted, either from a weather system or from an equipment failure, the Company is committed to restoring electricity to customers safely and quickly. Service restoration activities, from the line workers who work year-round to restore power, to the software and operational staff who help them work more efficiently, play a critical role in the timely restoration of service to customers during outages. Timely recovery of service restoration expense is essential to ensure resources are available to restore service as quickly as possible. The Company will be challenged to achieve further improvements in storm restoration service if it does not have timely recovery for the costs associated with such service.

Q. What was the Company's service reliability performance in 2025?

A. The Company's reliability performance in 2025 was significantly impacted by a high number of extreme weather events that included a historic ice storm in late March, 26 confirmed tornadoes in the Company's service territory, and another ice storm in late December. Due to the extreme weather, the Company's System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs") increased by eight minutes from 155 in 2024 to 163 minutes, and all-weather SAIDI increased from 503 in 2024 to 819 minutes.

Q. How did the extreme weather data for 2025 compare to 2024?

A. The state of Michigan experienced significantly stronger weather conditions in 2025 compared to 2024 in terms of quantity of events and severe weather events. As shown in Figure 1, 2025 saw a more than 20% increase in interruptions compared to 2024; this

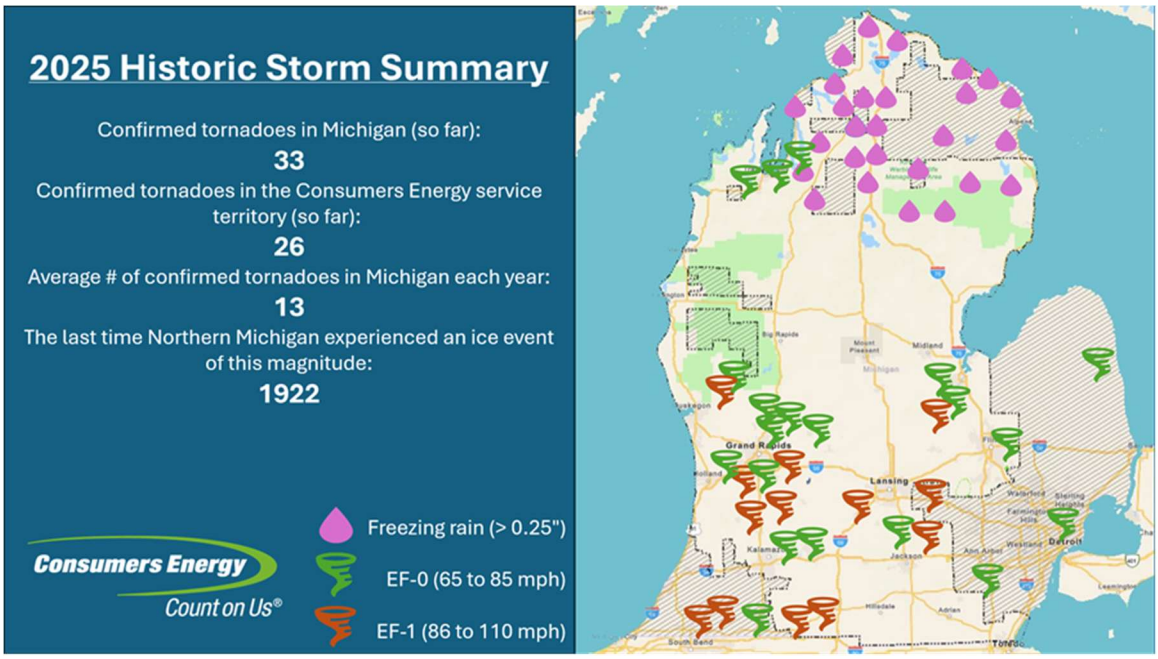
comparison alone fails to capture the full impact of the weather many Michiganders experienced last year.

Figure 1
2024 – 2025 Service Restoration Performance

Metric	2024	2025	2025 excluding March ice storm	Percent Change (2024 to 2025)
Total Interruptions	53,940	65,344	56,833	21.1%
Percent Restored within 24 Hours	93%	88%	91%	-5%
Service Restoration Expenses	$156.1M	$233M	$181.2M	16.1%

Compared to 2024, 2025 had a greater number of icing events, tornadoes, and thunderstorm-related wind gusts. In 2025, the Company's service territory experienced two significant ice storms. One of the events in late March was the worst ice storm northern Michigan has experienced since 1922. For comparison, there were zero significant ice storms in 2024. The year 2025 additionally brought a greater number of tornadoes compared to 2024. In 2025, there were 33 confirmed tornadoes in Michigan. Of the 33 confirmed tornadoes, 26 were reported in the Company's service territory. According to the National Weather Service, 2025 tied the year 1973 for the 3rd most active tornado season since 1950. In comparison, there were 17 confirmed tornadoes in Michigan in 2024. This data is succinctly captured in Figure 2 below.

Figure 2
2025 Historic Storm Summary



In 2025, there were also a greater number of thunderstorm-related wind gusts exceeding 75 mph compared to 2024. There was a total of seven reports of wind gusts exceeding 75 mph in 2025, compared to two reports in 2024.

Q. Is the Company satisfied with its holistic 2025 historical performance?

A. The Company is proud of its safe and efficient power restoration in the face of numerous catastrophic weather events in 2025, and it is leveraging digital tools and process improvements to further enhance its performance, as detailed later in my testimony. In this context, holistic performance refers to safety, restoration speed, customer impact, and system resilience. The Company has delivered relatively consistent year-to-year reliability in the face of historic weather events. The Company will not stop here though. The Company continuously evaluates its performance for opportunities to improve and restore power to customers even more quickly than it did in 2025.

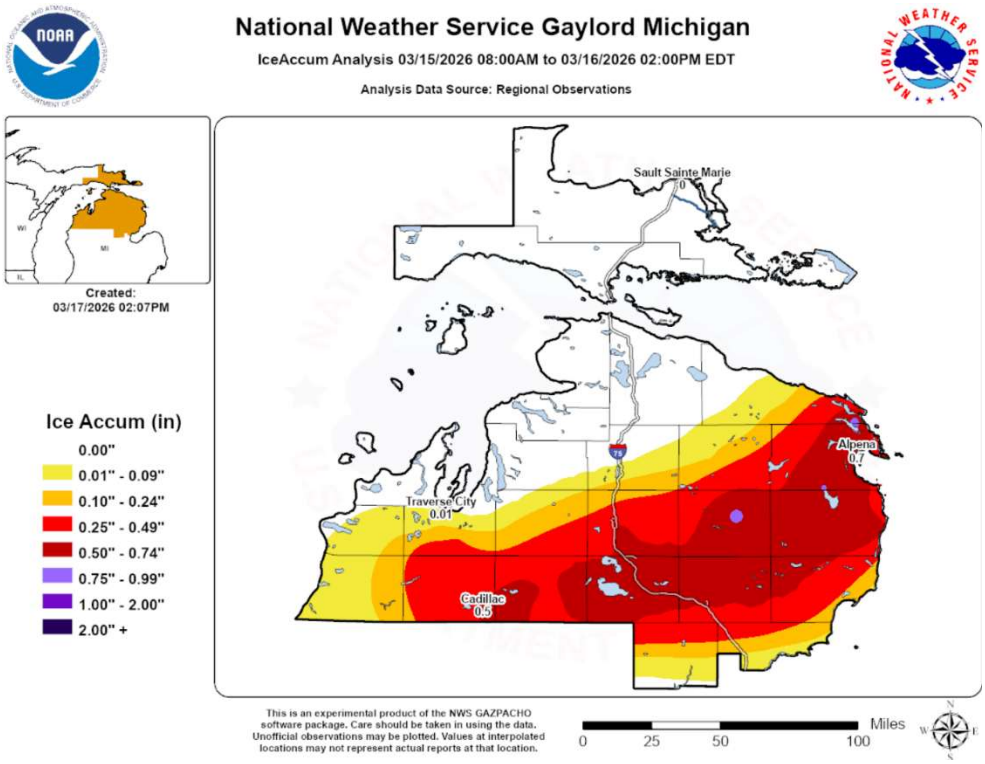
Q. What weather challenges has the Company experienced so far in 2026?

A. Severe weather has hit Michigan especially hard in 2026, bringing a full range of conditions – from tornadoes and freezing rain to flooding.

Q. Please describe the Company's work to restore from the March 2026 ice storm.

A. The Company restored power to more than 161,000 customers affected by the first storm system that moved through the state Friday, March 13th. The second wave of this storm system moved into the Company's service territory during the evening of Sunday, March 15th, bringing 60-mile-an-hour winds to the lakeshore and southern areas of the state, heavy snow measuring 30 inches in some areas and an icing event in the northern portion of the Lower Peninsula with ice amounts measuring 0.5 – 0.7 inches according to National Weather Service reports as shown below in Figure 3.

Figure 3
National Weather Service Ice Accumulation Analysis March 17, 2026



Even after the icing events ended, the accumulation of snow made many roads in northern Michigan impassable, delaying the restoration for many customers. In total, over 345,900 customers lost power from these storms between March 14th and 21st at a total cost of $96.5 million ($50.2 million in O&M and $46.3 million in capital).

Q. Please describe the Company's work to mitigate the risk from the flooding due to excessive rainfall.

A. In addition to ice storms, the Company also faced record-breaking rainfall and tornadoes in April 2026. Numerous waves of heavy rainfall and severe thunderstorms resulted in more than 106,000 customers without power during the week of April 13th with excessive rainfall being reported across the state, resulting in isolated locations reporting greater than six inches of rain. According to the National Weather Service office in Gaylord, several cities in northern Michigan set an all-time monthly rainfall record for April, and Northern Michigan is expected to have the wettest meteorological spring (March 1 - May 31) on record. Rivers, dams, and water-related infrastructure saw the greatest impact during the excessive rainfall event. The Muskegon River reported a river height of 19.49 feet on April 16, 2026. The previous record for the Muskegon River was 16.9 feet – set in April 2014. Perhaps the most notable event from this period came from Cheboygan County where a reported levee breach from the excessive rainfall resulted in widespread flooding and put thousands of residents on evacuation alert. The Cheboygan Dam was also impacted by the record rainfall event, where the height of the water was less than three inches away from overtopping. The Cheboygan Dam event also leveraged Emergency Preparedness' *Public Safety Power Shutoff (PSPS) Policy* that has been developed out of the Company's Wildfire Risk Mitigation Plan discussed by Company witness Emily M. Duke. The PSPS procedure

was developed in the event of needing to shut off customers' power to provide for public safety in the event of heightened wildfire risk. Although power was not shutoff, the Company leveraged the procedure to monitor the situation, evaluate a potential power shutoff, and proactively communicate to the community the potential need for shutoffs in the event of widespread flooding resulting from a dam breach.

Q. Has the Company seen increased tornado activity in 2026?

A. Yes. In addition to the widespread flooding, there were also nine confirmed tornadoes in Michigan during the week of April 13th. Of the nine confirmed tornadoes, seven were reported in the Company's service territory. The total number of tornadoes for 2026 climbed to 14, nine were in the Company's service territory. Michigan's annual average is 15 tornadoes.

Q. What has the Company learned from the volatile weather trend impacting Michigan and how is this reflected in your testimony?

A. These volatile weather trends have demonstrated the urgent need for timely recovery of service restoration spending to keep the power on for customers, businesses, and communities. Furthermore, the climate modeling included in the Company's Reliability Roadmap goes on to predict that severe weather will become more frequent in the coming years, meaning the Company will likely have to protect and restore its customers from similar events at a more regular cadence. My testimony lays out Consumers Energy's technological and operational initiatives to continue finding efficiencies as well as to ensure accurate restoration budgets and recovery of catastrophic storm spending through industry best practices.

Having the right people to respond to emergencies is a key risk mitigant, enabling the Company to proactively prepare for and respond to weather-related emergencies on the electric grid. As laid out in recommendation 3 from the Liberty Audit, the Company has increased its staffing in the Emergency Preparedness department (formerly Restoration Management) from six people in late 2024 to 17 as of March 2026. This includes succession planning for the five leadership roles, and a diversification of skill sets as broad as Meteorology, Data Science, and Lean.

Q. Has the Company increased staffing elsewhere to better improve restoration performance?

A. Yes. Through the continued improvement of reliability, the Company found an additional need for electric service workers ("ESWs") to improve onsite response time to customer reported outages and public hazards. Additionally, it allowed for further support of customer requested committed work. ESWs are the Company's first responders to all outages at all times of the day. Increasing the number of ESWs allows us to more effectively respond to emergent work orders, allowing us to arrive onsite sooner and removing safety hazards to the public. The addition of 13 ESWs in 2025 was an action taken to help mitigate outage response times and duration of customer outages.

Q. Where were the 13 additional electric service workers added?

A. Additional ESWs were added to the following locations:

- Two were added in **Grand Rapids** to help with emergent and customers committed work, ensuring we meet those commitments in the fastest growing city in Michigan.
- **Kalamazoo** added one ESW to support customer committed work, restoration work, as well as streetlight outages.

- **West Branch**, **Tawas**, **Boyne City**, **Traverse City**, **Benzonia**, **Cadillac**, **Big Rapids**, **Fremont**, **Battle Creek,** and **Coldwater** all added one ESW to improve restoration speed outside of normal business hours.

II. U-21914 STORM DEFERRAL REQUIREMENTS

Q. Please provide an overview of the 2025 March/April Ice storm.

A. Beginning on March 28, 2025, a series of severe weather events swept across Consumers Energy's service territory. The first wave brought rain, freezing rain, sleet, and winds of 30 to 35 miles per hour to northern Michigan, producing ice accumulations of up to 1.5 inches in areas such as West Branch, Tawas, and Boyne City. The National Weather Service confirmed that this was the worst ice storm to impact northern Michigan in more than 100 years. In response, Governor Whitmer issued emergency declarations for 13 counties.

A second severe weather event struck on March 30, 2025, affecting the southern portion of the service territory with hail, damaging winds, severe thunderstorms, and 14 confirmed tornadoes. The National Weather Service noted that Michigan's historical annual average is 13 tornadoes, making March 30 the highest single-day tornado count since 2001. A third wave of severe weather followed on April 2 and 3, bringing additional freezing rain, sleet, thunderstorms, and wind gusts exceeding 50 miles per hour.

These multi-wave storms caused widespread and significant damage to Consumers Energy's electric system affecting more than 391,000 customers, and extensive damage to transformers, poles, and conductors. Restoration required 636 transformers, 1,810 poles, and 220 miles of conductor, supported by more than 900 electric line crews and 300 forestry crews. Despite challenging conditions, including icy roads, fallen trees, debris, and the need to coordinate resources across a wide geographic area, all customers were restored by April 7, 2025.

Q. What was the Company directed to provide in the final order in Case No. U-21914?

A. In Case No. U-21914, the Company filed an application seeking ex parte accounting authority to defer storm costs related to the March/April Ice Storms of 2025. In the Final Order granting the Company's request to defer those costs, the Company was asked to provide comprehensive storm data, including a comparison to the February 2023 ice storm event. The Company was also ordered to demonstrate how its restoration efforts were conducted in a cost-effective manner through analysis of external resource requests data and identified opportunities to improve the cost-effectiveness of its storm response efforts. The Commission also directed the Company to compare different cost-recovery options, including amortization, securitization, return of the regulatory asset, and to demonstrate why the Company's preferred approach to cost recovery is in the best interest of its customers.

Q. What order requirements from Case No. U-21914 are you providing?

A. I am providing the following data, analysis, and review requirements:

- **Comprehensive Storm Data**: A breakdown of capital and O&M unit costs for internal and contractor crews;
- **Comparative Analysis**: Comparison between March/April 2025 storm event and February 2023 storm event;
- **Cost Effectiveness Review**: Demonstrate how the Company's restoration efforts were conducted in a cost-effective manner and how its customers experienced optimal restoration.

Company witness Hannah L. Patton compares the different cost recovery options cited in the U-21914 order and explains why the Company's preferred approach to cost recovery is in the best interest of its customers.

Comprehensive Storm Data

Q. What specifically was the Company directed to provide related to comprehensive storm data?

A. The Company was directed to,

> provide comprehensive storm data for the March/April 2025 event, including, but not limited to, at a minimum, a breakdown of capital and O&M unit costs for internal and contractor crews, separated by category. This information should be sufficiently comprehensive to evaluate the reasonableness of the company's expenditures during the storm event, including the unit cost breakdowns such as cost per crew, cost per worker, cost per case of trouble, cost per customer interruption, cost per customer minute of interruption, cost per pole installed, and cost per transformer installed.

Q. Please provide an overview of the Comprehensive Storm Data included in Exhibit A-85 (JPD-1).

A. As the comprehensive data in Exhibit A-85 (JPD-1) outlines, nearly 384,000 customers were impacted by a wind and ice event during the 2025 March/April ice storm with Company restoration activities lasting 189 hours. In total, the event cost $156 million, including $52 million in O&M expenses and $104 million in capital costs. The restoration efforts cost $18,240 per customer interrupted, or $0.27 per minute of customer interruption, and included the need to replace 1,810 poles at an average cost of $691 and 636 transformers at an average cost of $3,610.

Q. Please explain the difference between the estimated deferral of $96 million in O&M expenses in the original application, and the requested amount of $52 million in this case.

A. The destructiveness of the 2025 March/April ice storm resulted in less O&M work and more capital work than previously estimated. The deferral of $52 million in O&M reflects

the higher proportion of capital work than previously projected, including replacements of poles, cross-arms, and transformers detailed in Exhibit A-85 (JPD-1), as explained below in the Comparative Analysis section.

Comparative Analysis

Q. What specifically was the Company directed to provide related to comparative analysis?

A. The Company was directed to provide,

> a comparison of unit costs, number of resources, and storm characteristics (type of storm, number of outages, number of incidents, number of wires down, wire down response times, and duration) between the March/April 2025 storm event and the February 2023 storm event.

Q. What are the key similarities and differences between the 2025 and 2023 ice events?

A. The events were both driven by icing and wind; however, the 2025 event was much more destructive and difficult to restore compared to the 2023 event. The 2023 event impacted the more populous southern area of the Company's service territory and arrived in a single wave. As previously mentioned in my testimony, the 2025 event was the largest icing event in Michigan's history since 1922 and resulted in 0.5 to 1.5 inches of ice covering much of rural northern Michigan. Additionally, a second wave of severe weather impacted the southern portion of Consumers Energy's service territory, bringing hail, damaging winds, severe thunderstorms, and tornadoes. The arrival of the second wave forced the Company to allocate crews and resources between northern and southern Michigan further delaying a complete restoration. In total, the ice and strong winds from the 2025 event damaged over 700 more poles, 200 more transformers, and 1,700 more crossarms compared to the 2023 event which had less ice that thawed much more quickly, allowing for safer

conditions to conduct restoration efforts. These challenges were commonplace for other utilities in the region that were impacted by the event. Thousands of northern Michigan residents experienced powers outages up to 18 days due to the extensive destruction to infrastructure.[1]

Q. Please summarize the Comparative Analysis included in Exhibit A-85 (JPD-1).

A. The overall unit cost for labor, resources and materials was higher in the 2025 ice storm; however, restoration times were faster overall compared to the 2023 ice storm. During the 2025 event the Company replaced 73% more poles, 55% more transformers, and 92% more crossarms. Additional expenses were driven by aggressive storm preparedness strategy detailed further in Section III of my testimony, which enabled the Company to restore customers faster during the 2025 Ice Storm. As Exhibit A-85 (JPD-1) shows, the Company restored 33% more customers in under 48 hours compared to the 2023 event and reduced the total storm duration by 12 hours.

Q. What accounts for the higher cost of the 2025 storm event compared to the 2023 storm event?

A. The 2025 March/April ice storm was so damaging that the restoration work required was more characteristic of a complete rebuild rather than a simpler repair job,[2] requiring more labor and materials to restore power. As previously mentioned, the 2023 event is not directly comparable to the 2025 event; the damage from the icing was much more extensive, yielding greater challenges to repair damaged and broken equipment and restore

[1] Rick Brewer and Alvin (AJ) Jones, "*All Power Nearly Restored in Northern Michigan*," **WCMU Public Media**, April 17, 2025, https://www.wcmu.org/local-regional-news/2025-04-17/all-power-nearly-restored-in-northern-michigan.

[2] Schollett, Marc. "Northern Michigan Power Restoration Continues After Devastating Ice Storm." *WPBN/WGTU (UpNorthLive)*, April 7, 2025. https://upnorthlive.com/news/local/northern-michigan-power-restoration-continues-after-devastating-ice-storm.

customers. The 2025 storm also brought harsh winter conditions in the form of frozen ground and poor visibility which delayed restoration work and added to the overall cost. These challenges included the need for the Company to travel further distances in rural areas, clear roads, provide fuel trucks to power its vehicles and equipment, and the limited hotel availability for 826 crews. All these complications added time and costs to the work that needed to be completed in restoring customers.

Q. Please provide an example of the type of jobs that drove the increased cost for restoration work.

A. The damage and weather conditions the Company experienced as part of the 2025 March/April ice storms required increased labor, materials, and time to complete restoration work which drove the increased cost of the storm. As illustrated below in Figure 4, the ice snapped over 1,000 poles in half, and those that were standing often had damaged crossarms or transforms atop them. A common broken pole can be a time-consuming job, but in 2025, this work was often in wooded and rural areas of the Company's service territory that were difficult to access and required crews to clear broken trees, debris, and snow from the roads and rights-of-way prior to construction. Due to the ground conditions and the remoteness where the damage took place, some jobs required specialty vehicles that are engineered to travel through mud, ice, and snow. These trucks were a scarce resource and needed to be mobilized throughout the state. Once crews were able to access the damage, the crews saw a scale of damage that in many cases required complete rebuilding of large spans of distribution lines. Repairing damage this significant requires more materials, labor and most of all, time which drives the cost of overall storm restoration.

Figure 4
Example of Pole and Wire Replacement Work from 2025 March/April Ice Storm





Cost Effectiveness Review

Q. What specifically was the Company directed to provide related to cost effectiveness?

A. Related to Cost effectiveness, the Company was directed to:

> demonstrate how its restoration efforts were conducted in a cost-effective manner and how its customers experienced optimal restoration. To satisfy this evidentiary request, the company shall show, through its after-action review, how it has: (1) captured and analyzed data associated with external resource requests from the March/April 2025 storm event and (2) identified opportunities to improve the cost-effectiveness of its storm response efforts from the March/April 2025 event, with consideration given to whether the outage durations were efficiently managed.

Q. Did the Company conduct an after-action review?

A. Yes. The after-action review was completed by the Company eight weeks after demobilization of the March/April ice storm and was conducted with personnel who had key roles in incident response.

Q. Please summarize the data the Company captured and analyzed related to external resource requests.

A. The Company restored from the 2025 March/April ice storm utilizing only Company crews and field resources through its storm contractors process and did not require mutual assistance support as part of the restoration. Through efficient preplanning and storm preparedness, the Company was able to accurately predict the necessary resources to respond to the 2025 March/April ice storm and avoid more costly mutual assistance. As Exhibit A-85 (JPD-1) shows, the Company utilized 193 Company crews as part of the 2025 March/April storm restoration at an average crew cost of $126,000. The Company also utilized 636 contractor crews at an average crew cost of $119,000.

Q. What opportunities were identified to improve the cost-effectiveness of its storm response efforts?

A. The Company identified several opportunities to improve the cost effectiveness of its storm response efforts following the 2025 March/April ice storm:

- **Emergency Response Lodging Plan:** Refine lodging locations, activation triggers, and staffing plans to better match forecasted storm impacts. Improved pre-event lodging decisions can reduce unnecessary mobilization costs while maintaining employee safety, resulting in a partnership with Camp Grayling to house utility crews.

- **Advanced Distribution Management Systems ("ADMS") Improvements:** Better leverage ADMS capabilities to enhance restoration prioritization, reduce outage duration, minimize redundant field work, and lower restoration costs.

- **Materials & Time Charging:** Improve consistency and accuracy of material and labor time charging during storm response to strengthen cost tracking, support cost recovery, and improve future planning. Software has been implemented, streamlining the process of bringing contractor crews onto the Company's system by completing onboarding tasks before arrival.

- **Outage Prediction Model:** Develop more accurate outage prediction models to improve crew sizing, staging, and resource allocation. The Company is

collaborating with two universities to enhance predictive accuracy and avoid over- or under-deployment.

- **Intergovernmental Coordination:** Strengthen pre-incident coordination with federal, state, and local agencies through advanced communication and joint exercises. The Company has conducted a joint tabletop exercise with MSP Emergency Management & Homeland Security and has strengthened communication and coordination with the U.S. Forest Service, Michigan DNR, and local emergency managers.

Q. How did the Company demonstrate that customers experienced an optimal restoration while operating in a cost-effective manner?

A. The Company delivered an optimal and cost-efficient restoration for its customers by proactively mobilizing and pre-staging resources, ensuring customer safety during the event, and restoring customers faster from this historic event compared to previous ice storms. The Company prepared crew resources based on forecasted outages and pre-staged crews and resources near the anticipated icing impact area in advance of the weather. These efforts delivered a faster and safer restoration by having crews located in the right locations while avoiding dangerous and obstructed roads immediately following a storm. During an eight-day restoration which required crews to perform an unprecedented amount of work under stressful conditions, the Company kept customer safety top of mind with 0 public safety incidents. The Company's average wire down response time was more than three times faster in the 2025 March/April ice storm than it was in the 2023 ice storm as a result of better pre-staging which cut down on potential high energy risks to the public. Despite the severity of the damage and lingering effects of the ice on distribution assets, the Company restored 64% of customers in under 24 hours, and 86% of customers were restored in less than 48 hours while completing full restoration in 12 fewer hours than the 2023 ice storm.

III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

Q. What is the Company's projected service restoration O&M expense for the test year in this case?

A. The Company's projected service restoration O&M expense for the test year in this case is $192.6 million as shown in Company witness Duke's Exhibit A-90 (EMD-6), line 1.

Q. How did the Company determine this amount for projected service restoration O&M expenses for the test year?

A. The test year funding was calculated by inflating the historical year 2025 for the years 2027 and 2028, with costs for the 2025 March/April ice storms removed. The calculation for the test year considers eight months of the year 2027 and four months of the year 2028, the sum of which equals the test year amount of $192.6 million. The inflation rates for the years mentioned above are sponsored by Company witness Patton in her direct testimony at page 15, lines 1-4.

Q. Does the projected test year O&M include costs attributed to the 2025 March/April ice storm?

A. No. The $52 million in costs for the 2025 March/April ice storm are not included in the projected test year O&M expense calculation. This is consistent with the Commission's direction on page 3 of its June 12, 2025 Order in Case No. U-21914 that costs included in the regulatory asset for this storm, if ultimately approved for recovery in a future proceeding, not be included in any future rate case as part of a historical average calculation to inform a test year request.

Q. How much did the Company spend in calendar year 2025 inclusive of the March/April Ice Storm costs?

A. The total O&M spent on restoration in 2025 with the March/April ice storm O&M included was $233 million.

Q. How does the Company's Service Restoration proposal align with the recommendations raised by Liberty Consulting Group ("Liberty") in their Final Audit Report and with the method the Commission approved in the Company's last rate case (Case No. U-21870)?

A. The Company's proposed test year O&M expense aligns with Liberty's recommendations by producing an estimate that realistically considers the organization's expected needs for restoration resources in the test year. The Company and its customers have experienced an increase in severe weather which has led to increased service restoration costs. The Company's most recent historical year provides the most accurate benchmark based on projected service restoration performance requirements. The Commission approved the same approach (projecting the service restoration expense based on the most recent year of actual data adjusted for inflation) in the Company's last rate case. On pages 316-317 of the March 27, 2026 Order in Case No. U-21870, the Commission agreed that "the historical method of calculating Service Restoration expense left the program chronically underfunded" and that the Company's proposal in Case No. U-21870 was more aligned with Liberty's findings and recommendations.

Q. What is driving the increase in Service Restoration O&M expenses?

A. Increasingly severe weather in the Company's service territory and more intentional crew and resource pre-staging, or "preplanning," are the main reasons for the increased costs.

As discussed earlier in Section I, the Company has seen a steady increase in severe weather events which have resulted in more work to restore customers. In response to the increase in weather related outages, the Company has invested in additional resources to better predict the impact of storms and proactively mobilize resources in the field to get closer to the work when storms enter the Company's service territory.

Q. What is included as part of the Company's preplanning work for storm restoration?

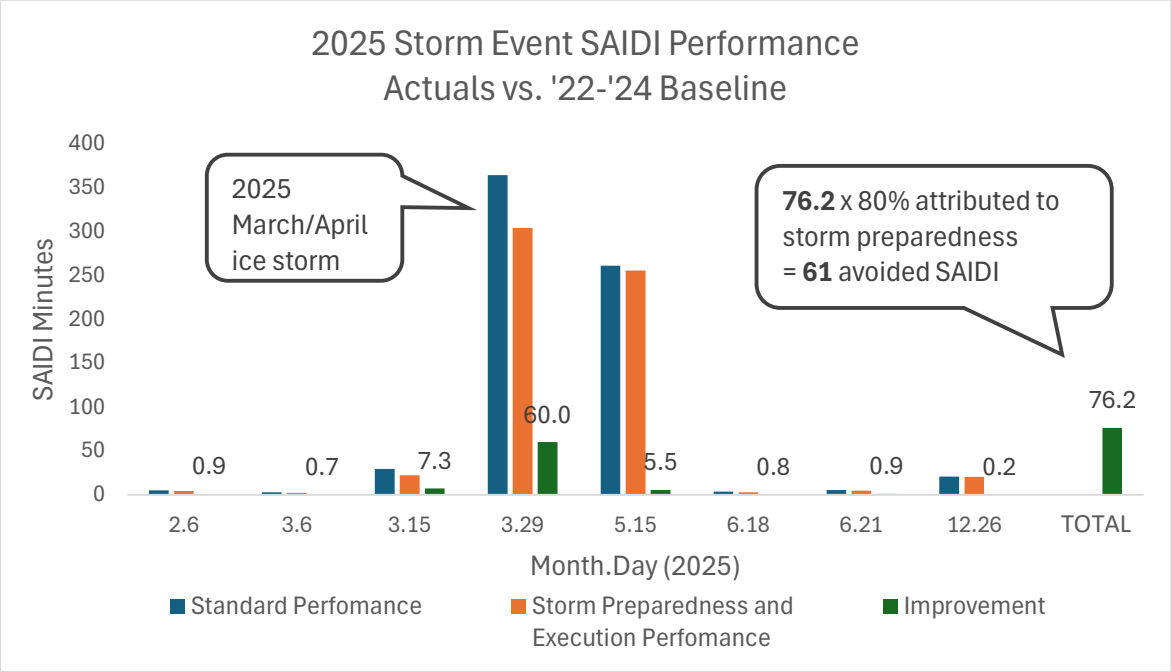
A. Preplanning starts with forecasting how the weather will impact the electric grid and involves mobilizing crews before severe weather strikes to have them on location ready to respond quickly to outages. The Company's Incident Command System is also staged to direct and support the restoration efforts. The Company pre-stages internal crews and contractor resources in or as close to predicted impact areas ahead of weather events to respond as quickly as possible to customer outages and hazards. Company crews may be pre-staged in their local headquarters or repositioned elsewhere in the state based on predictive weather models while contractor crews are also pre-staged at predicted highest impact locations. Pre-staging crews near forecasted impact areas greatly improves outage response times by eliminating the activation of crews and reducing the travel time required to restore customer outages and address public hazards.

Q. What benefits have customers seen from the Company's storm preparedness work?

A. The Company estimates that the storm preparedness approaches, including enhanced weather forecasting and pre-staging, avoided 61 All-weather SAIDI minutes in 2025. The calculation was derived by studying the eight storms where the Company saw performance improvement and applying 80% of the benefit to storm preparedness with 20% attributed

to the Control/Dispatch Center Consolidation project. These storms and their relative performance improvement are shown in detail below in Figure 5.

Figure 5
2025 Storm Event SAIDI Performance Improvement



Q. What was Liberty's recommendation regarding storm preparedness?

A. Part II of the Final Report included three recommendations specific to pre-event planning beginning on page 116, including:

- **Recommendation 5**: Classify weather events no later than when the decision is made as to whether available field resources will need to be supplemented and as early as data permits a reasonable assessment of a weather event's impact.

The Company understands the intent of this recommendation is to enable efficient storm restoration preparation performance by improving early storm event classification, identification of required resources, and pre-storm communication processes and procedures. The Company's storm preparedness work is the manifestation of this

recommendation which has improved the Company's restoration efficiency and reliability for customers.

Q. How did Liberty's recommendations impact the Company's storm preparedness process?

A. The Company reevaluated its storm preparedness strategy in 2024, after taking into consideration Liberty's feedback and recommendations, and made changes that began to immediately show promising results. The first significant test of storm preparedness came in with March/April 2025 ice storm. It was in this event that the Company forecasted the high likelihood of catastrophic storm risk approaching the service territory with multiple days of warning. The Company realized that its then-existing level and location of resourcing would not be able to adequately handle the expected damage to the system from the potential icing event. Immediately, the Company developed a plan to procure additional contracted resources and locate them along with Company resources at locations where the weather was most likely to impact customers and the distribution system. The Company did not wait to see the weather's impact but took prompt actions based on forecasted impact. These efforts delivered faster restoration times by having crews located in the right locations and increased safety by avoiding travel on dangerous and often obstructed roads immediately following the storm.

Q. What has been the financial impact of the Company's increased storm preparedness work?

A. In 2025, the Company spent $14.2 million more than it spent in 2024 to pre-stage contractor and Company crews, as shown in Figure 6 below. The amount accounts for 57% of the increase in Restoration O&M spend between 2024 and 2025.

Figure 6
2024 – 2025 Service Restoration Pre-Staging Costs

Metric	2024	2025	Difference
Contractor Pre-Staging	$9.4M	$21.5M	$12.1M
Company Crew Pre-Staging	$5.3M	$7.4M	$2.1M
Total Pre-Staging	$14.7M	$28.9M	$14.2M
Annual Service Restoration Expenses	$156.1M	$181.2M	$24.1M

Q. How has the Company improved its efficiency in storm restoration to lower costs?

A. The Company avoided $27.4 million in costs and 83.8 minutes of SAIDI in 2025 through improved storm preparedness and continued development of the Dispatch/Control Center Consolidation project. The breakdown of avoided costs and SAIDI are included below in Figures 7 and 8, respectively. In addition to the storm preparedness work detailed earlier in this section, the Company has improved its processes and activations by practicing for events before they occur. In 2025, the Company completed a preparedness exercise incorporating Public Safety Power Shutoff and conducted weekly storm team preparation meetings. The Company also expanded its use of Mobile Command Centers and field control, allowing more efficient restoration.

Furthermore, the Company continues to deploy the Control/Dispatch Center Consolidation which has been ongoing since Case No. U-21389. The benefits of this consolidation are described in detail in Section V of my testimony.

Figure 7
2025 Service Restoration Benefits Net Cost Avoided

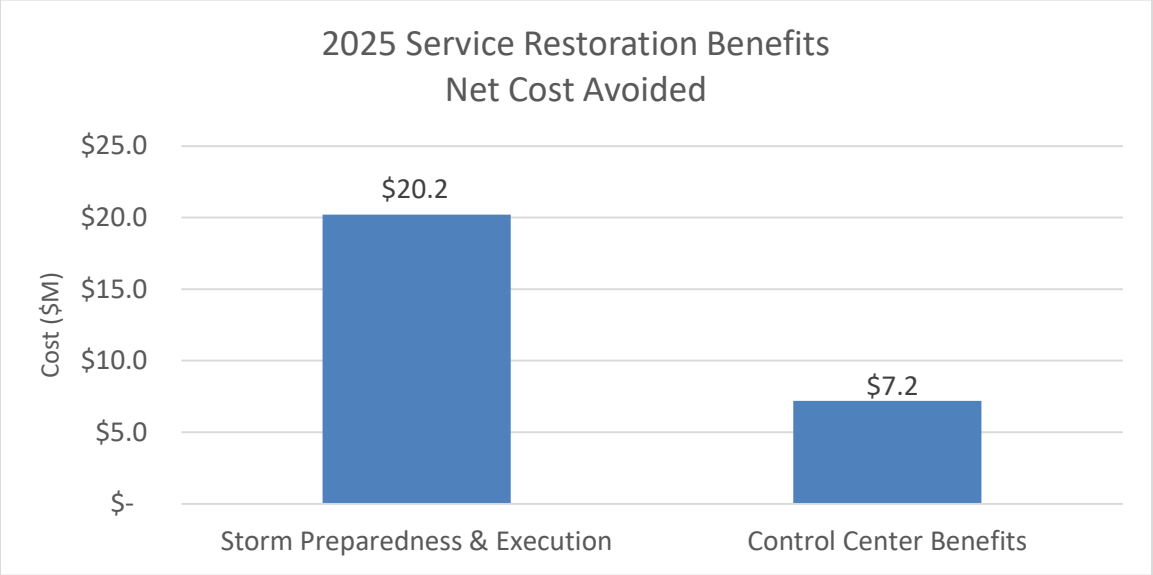
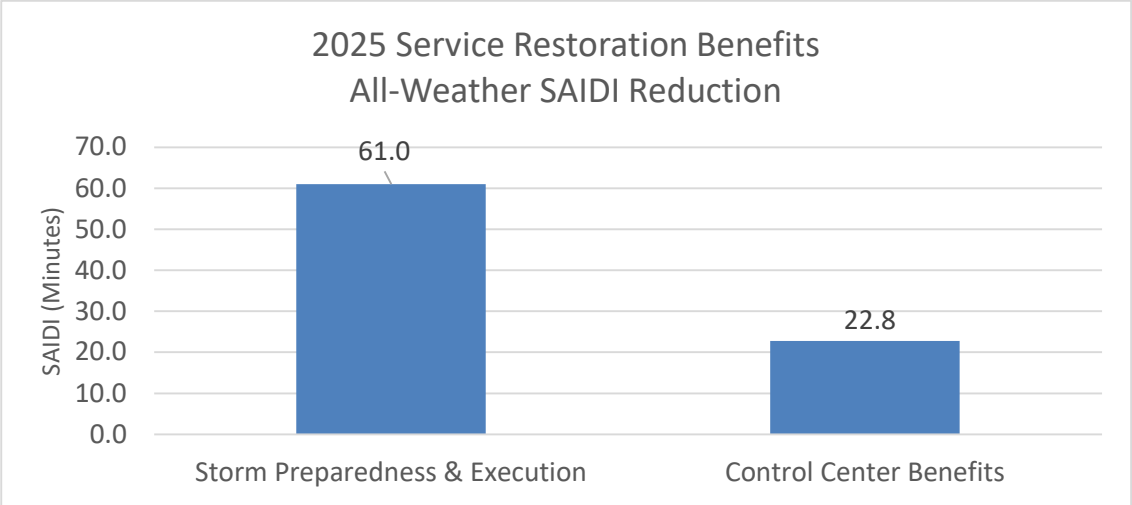


Figure 8
2025 Service Restoration Benefits SAIDI Minute Reduction



IV. DIGITAL AND PROCESS ENHANCEMENTS

Q. How will the digital tools and utilization of Machine Learning and AI benefit customers?

A. The Company has developed use cases where machine learning and AI can assist with faster and more consistent decision-making. Speed to execution is of critical importance

during restoration events, and AI's unique availability to simultaneously evaluate multiple datasets and assist with decision-making will reduce non-value-added time during restoration. Furthermore, AI's learning abilities enable decision-making to continuously improve, are unaffected by turnover, and mitigate learning curves as people transition from role to role.

Q. Does the Company have experience with Digital Tools and AI?

A. Yes. The Company has three strong examples of how digital tools and AI are benefiting customers each day. The examples include: the estimated time of restoration ("ETR") model used in the Company's outage map, the forestry workplan selection tool as discussed by Company witness Sara Stewart, and the insulator identification project discussed below in Asset Identification.

Q. What are the next use cases for digital tools and AI?

A. The Company has identified two main use cases for digital tools:

Event Resource Planning: The Company's priority with AI is focused on assisting with modeling resource needs based on weather forecasts. Today, the Company estimates the number of interruptions and subsequent customer outages based on weather forecasts. AI could assist with resource planning and optimize the Company's resource plan in a learning model. The savings opportunity for this use case is centered around the efficient utilization and mobilization of resourcing and precise staging for events, and real time crewing adjustments. The ultimate target is for the actual resource plan to perfectly match the event size, thereby creating savings for customers by ensuring the most efficient resource planning.

Asset Identification: The Company's second priority with AI is Asset Identification. In 2024, the Company developed an asset identification AI model that learned what problematic insulators on the High Voltage Distribution (HVD) system look like. The model then examined photographs from aerial patrols to identify the structures containing the problematic insulators. A similar application could be applied to facility identification during storm restoration. For example, with a simple photo provided by a customer, AI could quickly distinguish Company-owned facilities from third-party facilities and help prioritize wire-down response. An AI application could improve public safety and response efficiency by routing resources faster to where they are most needed.

V. CONTROL/DISPATCH CENTER CONSOLIDATION

Q. Please summarize the Company's proposal for Control/Dispatch Center consolidation.

A. The Company's proposal involves modernizing System Control, Distribution Control, and Dispatch Centers into two fully staffed control centers—one in Jackson and one in Grand Rapids. Two fully staffed facilities are essential to ensure operational continuity, enhance resilience, and maximize the benefits of improved resource allocation and operational efficiency during both blue sky and major outage events.

The project is a targeted reliability investment that has and will continue to deliver enhanced system operations and emergency response capabilities. The Company's Control/Dispatch Centers function is a core element of electric distribution operations, directly overseeing system monitoring, outage management, and coordinated field response. These activities are operational in nature and integral to faster service restoration, particularly during severe weather events leading an effective response prior to leveraging the benefits of a full ICS activation. Each Control Center incorporates modern

control-room design standards, including integrated telemetry, outage visualization, and optimized operator workstations, which improve real-time situational awareness and support more effective operational decision-making during major outage events.

Q. How are the Control Centers operating today, and why is further Control/Dispatch Center consolidation still necessary?

A. Currently, the Company is operating its consolidated Control/Dispatch functions more efficiently and effectively than ever. Since closing the Saginaw Dispatch Center in 2022 and consolidating operations into Jackson and Grand Rapids, the Company has improved coordination, strengthened operator readiness, delivered measurable improvements in restoration performance and reliability, and reduced costs. However, these gains have been achieved within legacy facilities that were not designed to support the staffing needs, grid automation deployment, integration, or redundancy required by the modern consolidated operating model. As responsibilities and 24/7 operational demands have expanded, both locations are increasingly constrained by space, outdated infrastructure, and limited mechanical and electrical redundancy. In addition, key control functions, including System Control (HVD) activities, remain physically separated, limiting full operational integration. See Figure 9 of current legacy consoles for dispatch, Figure 10 for Distribution Control Center ("DCC"), Figure 11 for proposed operator desks, and Figure 12 for Grand Rapids Control Center mock-up.

Figure 9
Legacy console operations performing dispatch tasks

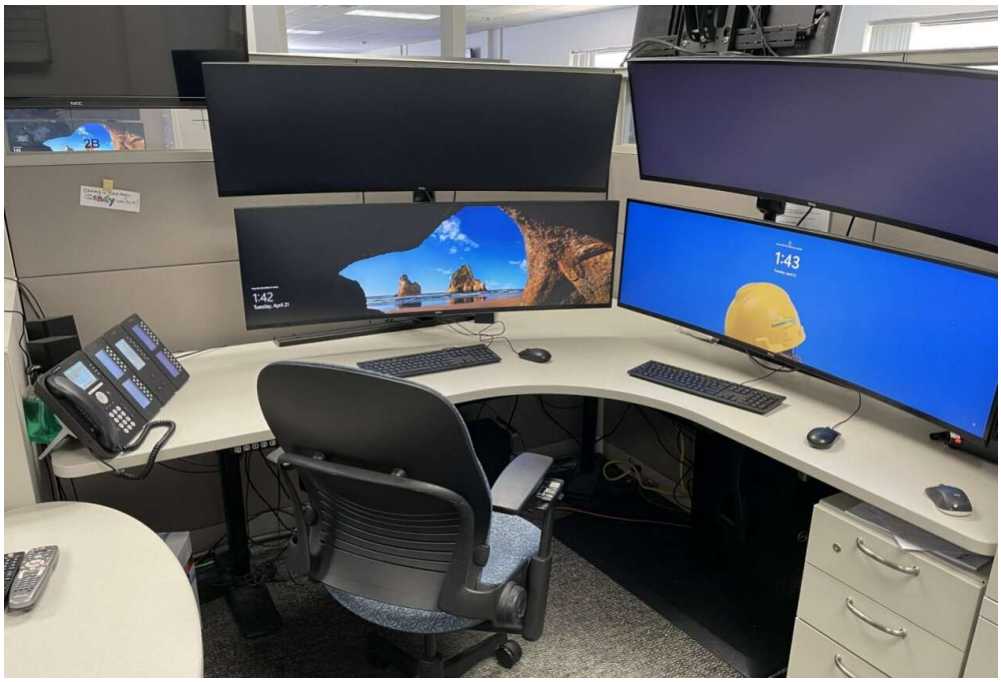


Figure 10
Legacy console operations performing DCC tasks

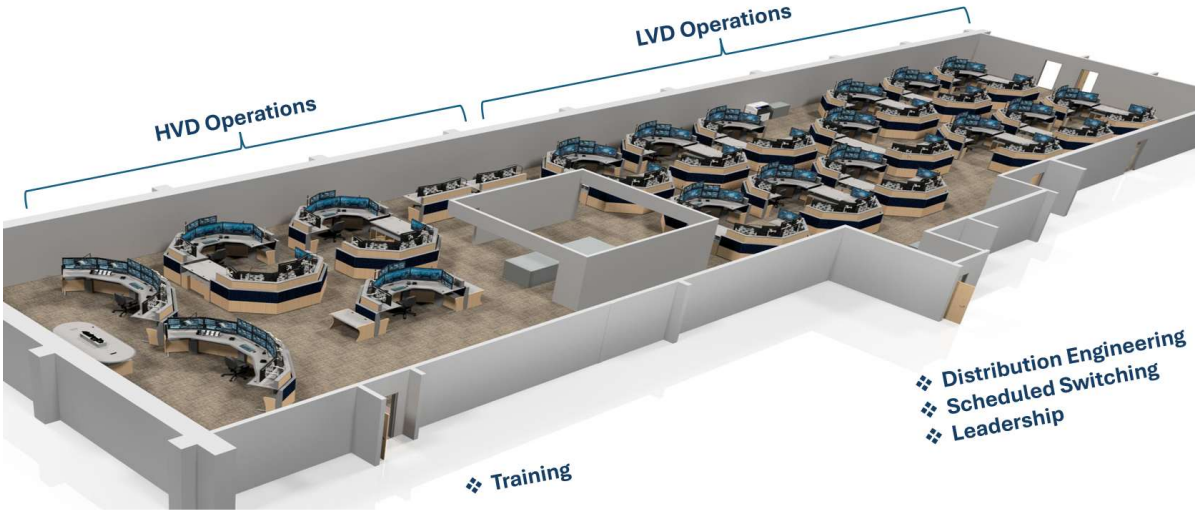


The Control/Dispatch Center consolidation and modernization project represents the next necessary step – transitioning from high-performing but constrained legacy spaces to purpose-built facilities designed to support the evolving electric grid. These new facilities are designed to accommodate increased grid automation, expanded real-time monitoring and controls on the grid, and enhanced visibility into system and line status as advanced grid technologies are deployed. Additionally, co-locating HVD Operators, Low Voltage Distribution (LVD) Operators, real-time Distribution Engineering, and Scheduled Switching enables faster information sharing, improved situational awareness, and more coordinated decision-making.

Figure 11
Console performing integrated HVD Operator or LVD Operator performing Dispatch and DCC tasks



Figure 12
Example of consolidated control/dispatch center consolidation of Grid Operators (HVD, LVD) and support teams surrounding the center; proposed Grand Rapids Control Center



Q. What other benefits does an integrated environment offer?

A. An integrated operating environment enables more effective use of modern tools – such as Advanced Distribution Management System, grid automation, and real-time telemetry – which are increasingly critical as the grid grows more complex and faces more frequent severe weather events. These capabilities enhance early issue detection and further enable active operator control of the grid. As detailed in the testimony of Company witness Scott A. McPhail, beginning on page 16, line 9, operators utilize Fault Location, Isolation, and Service Restoration ("FLISR") functionality to isolate faults, reconfigure the system, and restore service with reduced reliance on field response, supporting safe and efficient restoration and improved system reliability.

Q. How does two Control/Dispatch centers provide faster, more reliable service for customers?

A. Operating two fully staffed Control Centers improves reliability for customers by enabling faster outage detection and restoration while providing built-in operational resilience, ensuring minimal impact if one center is disrupted and supporting effective response during severe weather or major events. This dual-center redundancy ensures customers regain service safely and more quickly.

Several key benefits support this improved customer experience:

- **Resilient Operations in Practice:** In emergency situations, the Company's centers can immediately support one another to maintain continuous service. For example, during the April 2, 2025 severe weather event, tornado warnings required evacuation of one dispatch center. Within minutes, the alternate center assumed full storm restoration responsibilities, preventing delays in service restoration for customers.

- **Workforce Flexibility and Depth**: Staffing two geographically separate locations provides greater workforce depth and flexibility, improving operational readiness and the Company's ability to sustain extended restoration efforts during large-scale events.

- **Operational Efficiency and Faster Restoration**: Consolidated centers enhance system visibility by integrating outage management systems, Supervisory Control and Data Acquisition ("SCADA"), and telecommunications networks. This improved situational awareness allows operators to identify issues sooner, dispatch crews more efficiently, execute switching decisions faster, and coordinate restoration activities more effectively.

Q. How does the Control/Dispatch Center consolidation project improve restoration efficiency?

A. The consolidation improves restoration efficiency by strengthening operational readiness, coordination, and continuity throughout storm response and recovery. Two fully staffed centers support more effective pre-storm planning, increased operator availability, and sustained focus during extended outage events. Enhanced real-time communication and

integrated system awareness enable faster damage assessment, more efficient resource deployment, and adaptive restoration strategies as conditions change. The consolidated centers also improve monitoring and management of the telecommunications infrastructure that supports SCADA, automated switching, outage management, and FLISR functionality. This capability is necessary to help ensure that investments in advanced grid technologies deliver their intended reliability benefits.

As operational processes, staffing models, and supporting technologies associated with the consolidation continue to be fully implemented, the Company expects further improvements in restoration speed and predictability delivering customer benefits described below.

Net Cost Avoided:

- Service restoration annual net cost avoidance: $10.1 million.
- Facilities/IT/Training expense annual savings: $0.1 million.

Total Annual Net Cost Avoided: $10.2 million.

Outage Response Benefits:

- All-weather SAIDI benefit: 20.8 minutes.

Project Cost and Implementation: Test and Bridge Year cost: $20.1 million in the bridge period and $1.6 million in the test year.

Completion timeline: Construction, commissioning, and occupancy of the two fully staffed control centers by early 2027, including the integration of real time Distribution Engineering groups.

Q. What are the projected costs associated with this project in the Bridge Period and Test Year?

A. The Company projects a total expenditure of $20.1 million capital in the bridge period and $1.6 million capital in the test year. These costs support the completion of construction, commissioning, and occupancy of the control centers by early 2027, as well as the integration of real time Distribution Engineering operations within the consolidated control centers. The capital costs for this project are detailed in Company witness Quentin A. Guinn's Exhibit A-135 (QAG-3), page 1, lines 21 and 22, along with the associated testimony.

Q. What were the projected and actual costs associated with this project in 2025?

A. In Case No. U-21870, for 2025, the Company projected $5.9 million in capital and $0.7 million in O&M costs for the Control/Dispatch Center Consolidation project. In 2025, the Company incurred $5.5 million in capital and $0.3 million in O&M costs for the Control/Dispatch Center Consolidation project. These expenditures covered design services, material acquisition, and initial space renovations. The difference in projected versus actual spend was $0.8M. This was due to a delay in design services and relocating existing employee facilities.

Q. What milestones of this consolidation project have been completed as of the end of 2025?

A. Milestones for this project can be grouped into three categories: Building & Facilities, Process Efficiencies, and Operator Training and Workforce Readiness Enhancements. As of the end of 2025, the following milestones have been completed in each of these categories:

- **Building & Facilities**:
    - Consolidated three legacy dispatch centers into two existing fully operational sites in Jackson and Grand Rapids, reducing facility redundancy while strengthening system oversight.
    - Completed required environmental remediation, including asbestos removal, to prepare both sites for long-term use.
    - Finished initial design and engineering for the consolidated facilities, as documented in Company Witness Guinn's Exhibit A-XXX (QAG-6), pages 10–11.
    - Advanced construction readiness by issuing approved design plans for bidding, initiating contractor engagement, and procuring long-lead equipment and materials necessary for control center build-out.
    - Reconfigured existing facilities by relocating a laboratory in Jackson and a contact center in Grand Rapids to create space for expanded control center operations.
- **Process Efficiencies**:
    - Expanded the Jackson Control Center from limited weekday coverage to 24-hour, 7-day continuous operations, improving system visibility and operational continuity.
    - Operationalized DCC desk in Jackson, enabling real-time load transfers, circuit-level outage response, and concurrent execution of safety and restoration activities across the service territory, resulting in more coordinated and faster customer restoration.
- **Operator Training and Workforce Readiness Enhancements**:
    - Strengthened workforce readiness by establishing dedicated staffing to support classroom training, structured on-the-job instruction, and simulator-based testing without reducing real-time operational coverage. These enhancements support consistent operator response, improved decision-making, and faster execution of switching, crew dispatch, and restoration strategies across the consolidated Control/Dispatch Centers.

Q. What work remains to be done for the Control/Dispatch Center Consolidation project?

A. The Company is renovating both the Jackson and Grand Rapids Control Centers. Construction has started and is ongoing through the end of 2026 into 2027. The Company

will, therefore, incur the bulk of its costs for this project during the bridge period. The Company's costs are discussed further below.

As the Control/Dispatch Center Consolidation project continues, the Company will further advance the operating model through continued operator training, cross-training, and workforce development. This includes expanded cross-training of dispatch and DCC tasks to increase operator flexibility, depth, and consistency across both consolidated centers, enabling operators to effectively manage a greater number of field crews simultaneously and lead faster, more coordinated restoration efforts.

The Company will also complete the transition of the Jackson DCC desk to continuous 24-hour, 365-day operation, ensuring full coverage for both storm and non-storm system conditions. In parallel, the Company will continue working with operators and leadership to strengthen operational readiness for small- to medium-scale events, enabling effective system management and restoration with limited reliance on full ICS activation. Collectively, these efforts are intended to further improve decision-making, optimize resource utilization, and strengthen restoration speed and predictability, and maximize the operational and cost efficiencies of the consolidated Control/Dispatch Center structure for the benefit of customers and reducing costs.

Q. What cost avoidance and reliability benefits were realized in 2025 from the Control/Dispatch Center Consolidation project?

A. In 2025, the Company both avoided 22.8 all-weather SAIDI minutes and $7.2 million in costs exceeding the projected annual benefits. Initially, the Company set 7.5 all-weather SAIDI minutes and $4.2 million costs as a target savings for 2025. Benefits for this project

can be grouped into three categories: Saginaw Consolidation, Jackson DCC, and Control Center Efficiencies. See Figures 13 and 14 for the benefits breakdown.

Figure 13
2025 Control Center Benefits Net Cost Avoided

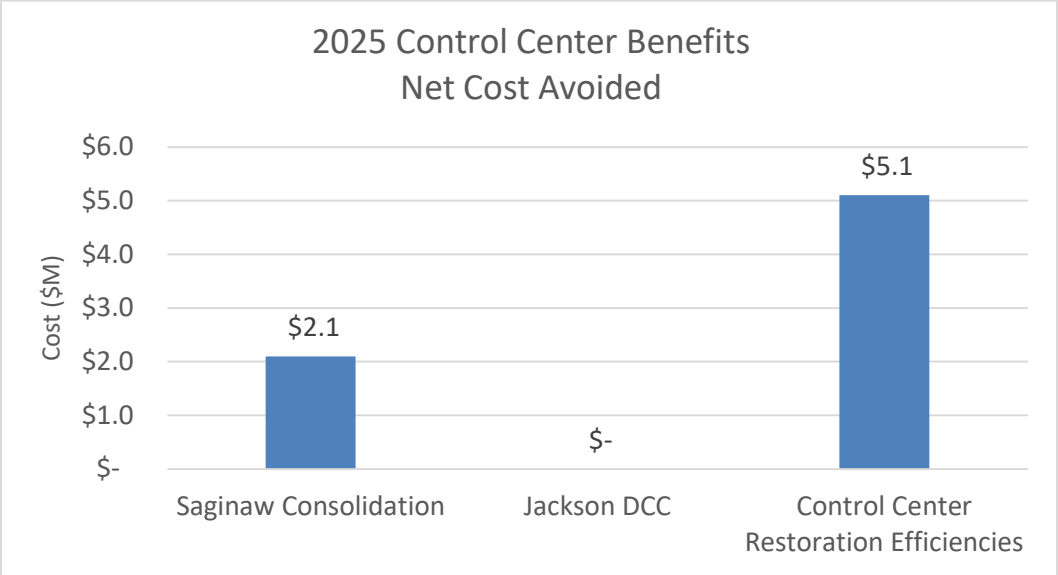
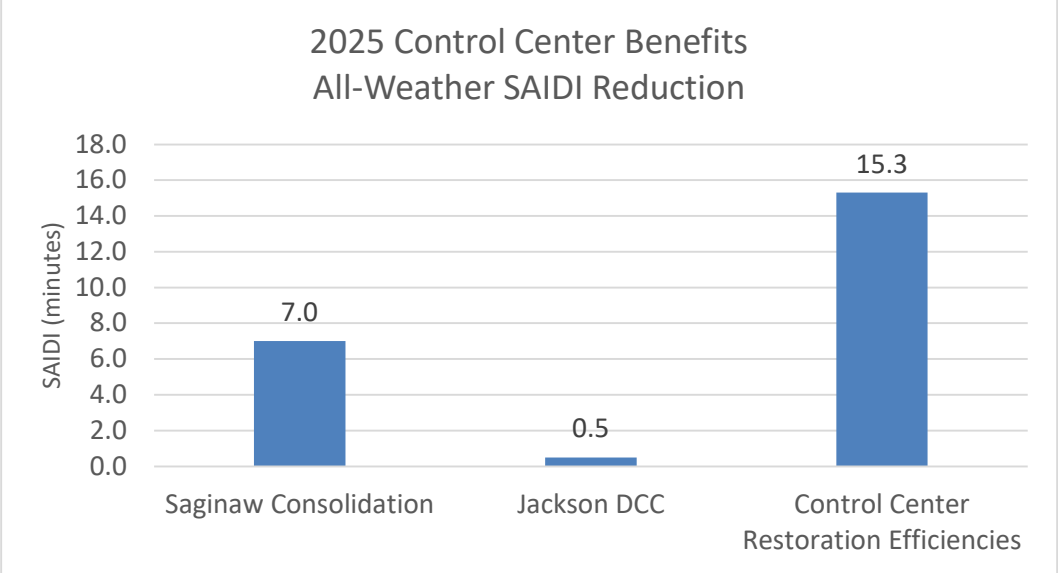


Figure 14
2025 Control Center Benefits All-Weather SAIDI Reduction.



Below are details of each benefit:

- **Saginaw Consolidation:** The consolidation of three Control/Dispatch Centers into two resulted in approximately $2.1 million in avoided service restoration

costs and an estimated 7.0 all-weather SAIDI minutes avoided in 2025. These benefits were driven by improved incident coordination, operation with two Incident Command System teams instead of three, and better alignment of dispatch boundaries and workloads. Collectively, these changes reduced overtime costs and supported faster, more efficient restoration.

- **Jackson DCC:** Routine load transfer operations performed by the Jackson DCC during non-storm ("blue sky") conditions contributed an additional 0.5 all-weather SAIDI minutes avoided in 2025. These proactive actions improved day-to-day system reliability and reduced customer outage exposure.

- **Control Center Efficiencies:** Improved restoration performance under the consolidated operating model produced additional benefits, including approximately $5.1 million in avoided restoration costs and 15.3 all-weather SAIDI minutes avoided in 2025. These results are supported by event-level historical storm analysis comparing restoration performance across comparable storm events and system conditions, which demonstrated consistently improved restoration outcomes under the consolidated operating model. These improvements were enabled by enhanced DCC capabilities, integrated system awareness across control centers, and operator training that increased operator capacity during storm events, allowing operators to safely manage more field crews and coordinate restoration more effectively with Incident Command leadership.

Q. Have the projected total cost saving and SAIDI improvements for the project changed in 2026-2027?

A. No. See Figures 15 and 16 below.

Figure 15 illustrates the ramp-up of net cost benefits and Figure 16 illustrates the ramp-up of SAIDI benefits.

Figure 15
Annual Progression of Net Cost Avoided.

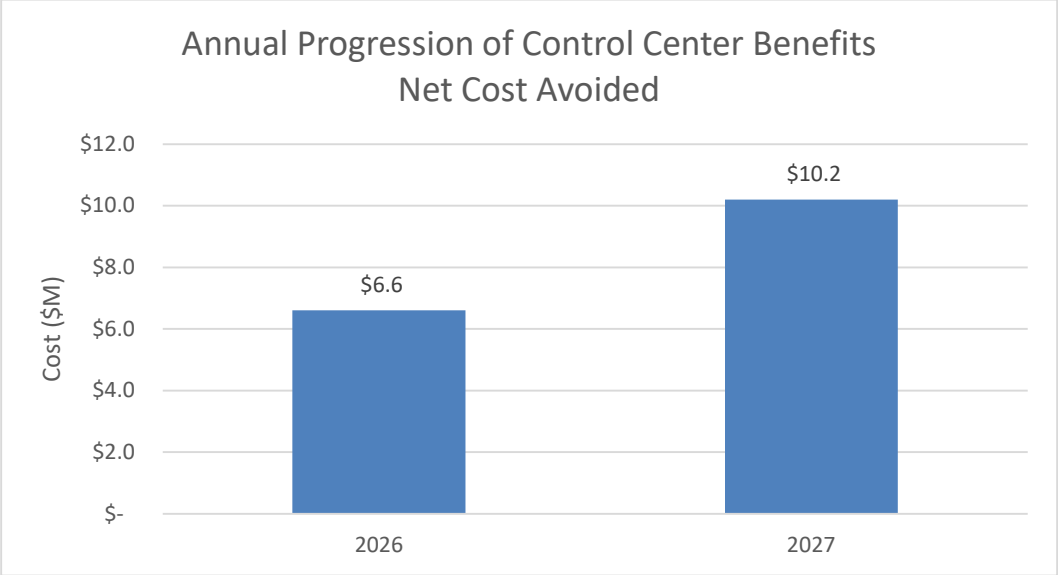
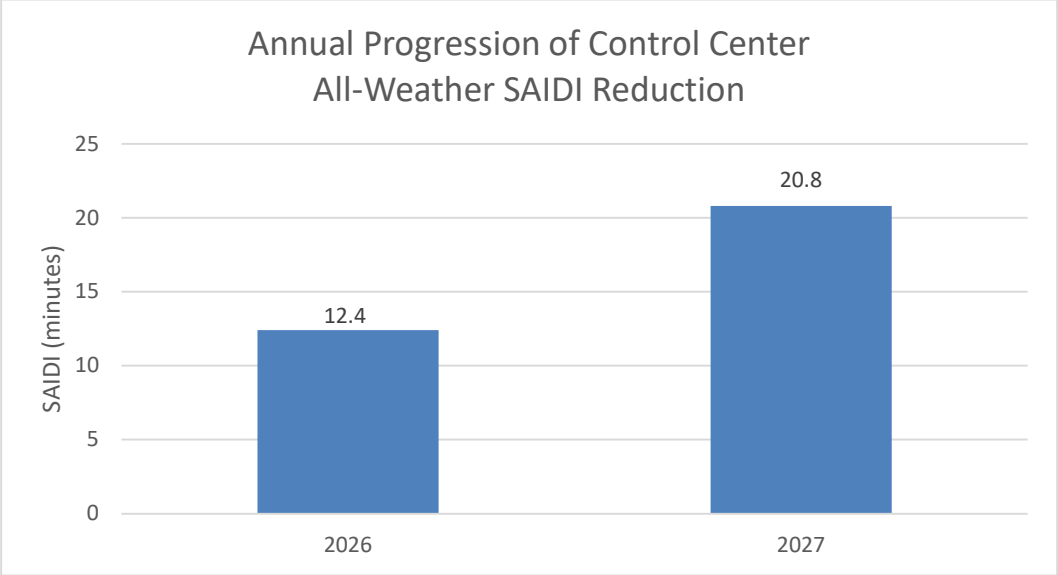


Figure 16

Annual Progression of All-Weather SAIDI Reduction



VI. SUMMARY

Q. Please summarize your testimony?

A. In this testimony, I have provided an overview of recent restoration performance in the face of increasing severe weather threats, the automation, operational and facility modernization enhancements underway to improve the Company's restoration

performance, and the financial resources necessary to achieve this. I also provided comprehensive storm data, comparative analysis, and cost effectiveness proposals following the historic March 2025 ice storm, as required in Case No. U-21914.

In the face of escalating severe weather including ice, tornadoes, wind, and thunderstorms, the Company recognizes the need to continue raising the bar on reliability performance. To support this objective, the Company has adopted industry best practices to better predict the weather impacts, proactively mobilize resources, and coordinate restoration efforts. Preparedness enhancements recommended by Liberty have strengthened the Company's ability to respond effectively to outages, particularly during large-scale and catastrophic events.

Similarly, the Control/Dispatch Center Consolidation and Modernization project continues to improve operational efficiency and reliability through operator-driven grid control and automation, resilient and redundant operations, increased operator capacity through training and consolidation, more efficient resource mobilization, and safer execution of restoration activities. Together, these initiatives support the O&M spending plans outlined in this testimony and the capital investments detailed in the direct testimony of Company witnesses Guinn and are intended to deliver sustained reliability improvements and cost-effective service for the Company's customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

EMILY M. DUKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Emily M. Duke, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently a Senior Strategy Manager in Electric Distribution Strategy.

Q. What is your formal educational experience?

A. In 2008, I received a Bachelor of Arts in Finance from Michigan State University. In 2021, I received a Master of Business Administration from the University of Michigan – Ann Arbor.

Q. Please describe your business experience.

A. From 2008 to 2011, I was employed by Wells Fargo as an investment banking analyst. From 2011 to 2015, I worked as a financial analyst at Atlas Energy L.P., an oil and gas exploration and production company. I joined Consumers Energy in 2016 as a senior financial analyst in the Enterprise Risk department. In this role, I facilitated the enterprise risk management program, which consisted of working with risk owners across corporate and operational groups, to identify and analyze risks. From 2017 to 2021, I was a senior associate in the Corporate Strategy department where I was responsible for managing the gas, electric, and retail businesses and supporting organization's strategy development. From 2021 to 2023, I was the Manager of Supply Contracts in the Electric Grid Integration Contract and Settlements department where I was responsible for implementing the Company's Clean Energy Plan as well as managing the Renewable Energy Plan,

Experimental Advanced Renewable Program, Renewable Energy Credit administration and compliance; and supply procurement for the Company's Voluntary Green Pricing Programs. In 2023, I started in my current role as Senior Strategy Manager in Electric Distribution Strategy.

Q. What are your responsibilities as Senior Strategy Manager in Electric Distribution Strategy?

A. My responsibilities as Senior Strategy Manager in Electric Distribution Strategy include development of the Company's *Electric Distribution Infrastructure Investment Plan* ("EDIIP," also referred to as the "Reliability Roadmap") and implementing the Electric Distribution department's planned activities consistent with its financial plans.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC cases under the name Emily M. Walainis:

Case No. U-20604	Approval of Power Purchase Agreements;
Case No. U-20803	2021 Power Supply Cost Recovery ("PSCR") Plan Reconciliation;
Case No. U-21009	2020 Renewable Energy Cost Reconciliation;
Case No. U-21048	2022 PSCR Plan;
Case No. U-21049	2022 PSCR Plan Reconciliation;
Case No. U-21131	Legally Enforceable Obligation under the Public Utility Regulatory Policies Act of 1978;
Case No. U-21134	Voluntary Green Pricing Programs;
Case No. U-21197	2021 Renewable Energy Cost Reconciliation;

Case No. U-21257	2023 PSCR Plan;
Case No. U-21352	2022 Renewable Energy Cost Reconciliation; and
Case No. U-21423	2024 PSCR Plan.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's electric distribution strategy. I will begin my testimony by providing an overview of how the Company's distribution strategy has been developed and how it has evolved in recent years. I will discuss how the Company measures electric reliability performance as well as its past actual and projected future reliability performance, based on the impact of the distribution investments proposed in this electric rate case. I will discuss how the Company has established objectives for its distribution system and how these objectives govern the Company's investments.

Next, I will explain the strategic objectives that guide the Company's investment decisions to achieve reliability performance in the face of the increasingly challenging weather conditions, customer technology adoption, and system deterioration. I will explain the technology projects that support electric distribution as well as the Company's projected electric distribution operating and maintenance ("O&M") spending.

Finally, I will address certain issues related to advanced metering infrastructure ("AMI").

Q. Are other Company witnesses addressing the Company's electric distribution strategy and investments?

A. Yes. To provide comprehensive support for the Company's electric distribution requests, six additional witnesses are providing evidence in this proceeding. Company witness

Jennifer M. Partlan will support the Company's historical and planned capital investments in the Low Voltage Distribution ("LVD") system. Company witness Kurt K. LaFrance will support the Company's historical and planned capital investments in the High Voltage Distribution ("HVD"), substations, and Metro systems. Company witness Scott A. McPhail will support the Company's historical and planned capital investments in the Grid Automation Program. Company witness Daniel A. Schmoekel will support the Company's historical and planned capital investments in streetlighting. Company witness Sara E. Stewart will support the Company's historical and planned spending for the Forestry Line Clearing Program. Company witness Jeffery P. Dickey will support the Company's historical and forecasted spending in Service Restoration.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (EMD-1)	Schedule B-5.6	Electric Distribution Summary of Actual and Projected Capital Expenditures;
Exhibit A-86 (EMD-2)		Electric Distribution Actual and Projected Capital Expenditures – Cost Splits;
Exhibit A-87 (EMD-3)		Electric Distribution Actual and Project Capital Expenditures – 5yr Historical;
Exhibit A-88 (EMD-4)		Electric Distribution Actual and Projected Capital Expenditures – Over/Under $5 Million;
Exhibit A-89 (EMD-5)		Electric Distribution Summary of Actual & Projected O&M;
Exhibit A-90 (EMD-6)		Electric Distribution Detailed Summary of Actual & Projected O&M;

Exhibit A-91 (EMD-7)	Electric Distribution Actual & Projected O&M Cost Splits;
Exhibit A-92 (EMD-8)	Electric Distribution Actual and Projected O&M Using Inflation;
Exhibit A-93 (EMD-9)	Electric Distribution Detailed Summary of Actual & Projected O&M;
Exhibit A-94 (EMD-10)	Electric Distribution Summary of 5yr Historical and Projected O&M Expenses;
Exhibit A-95 (EMD-11)	2025 Reliability Roadmap;
Exhibit A-96 (EMD-12)	2021-2025 Distribution Unit Costs;
Exhibit A-97 (EMD-13)	Reliability Regression Analysis for Environmental Justice Communities;
Exhibit A-98 (EMD-14)	Reliability and Disconnections Regression Analysis Overview and Observations;
Exhibit A-99 (EMD-15)	Mitigating Wildfire Risk in Consumers Energy's Service Territory (2026-2030);
Exhibit A-100 (EMD-16)	Advanced Metering Infrastructure Metrics and Elements;
Exhibit A-101 (EMD-17)	Electric Distribution Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11;
Confidential Exhibit A-102 (EMD-18)	Consumers Energy Wildfire Risk Assessment Final Report; and
Exhibit A-103 (EMD-19)	Comparison of Distribution Plan and Instant Case for Part III Requirement #170.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is calendar year 2025. The bridge period consists of the 16 months beginning January 1, 2026, and ending on April 30, 2027. The projected test year is the 12 months beginning May 1, 2027, and ending on April 30, 2028.

Q. How is your testimony organized?

A. Below is a Table of Contents that sets forth the subjects of my testimony.

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Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes. I will note that the Regression Analysis at Exhibit A-97 (EMD-13), the summary at Exhibit A-98 (EMD-14), and the Wildfire Risk Assessment at Confidential Exhibit A-102 (EMD-18) were prepared by third-party consultants working with the Company.

I. EXECUTIVE SUMMARY

Q. What is the recent history of the Company's approach to distribution planning?

A. The Company has produced a series of five-year distribution plans known as the EDIIP, the first of which was filed in March 2018, in Case No. U-17990. The first EDIIP dealt largely with the Company's then-existing distribution planning processes, providing visibility for the Commission and other regulatory stakeholders. Since then, the Company's approach to planning has evolved to include new tools and methods of analysis to better anticipate future challenges, with those changes reflected in successive versions of the filings. The most recent formal iteration of this five-year plan—the third EDIIP—was filed in September 2023, in Case No. U-20147. Beginning with this September 2023 filing, the EDIIP is also known as the "Reliability Roadmap," and that is the term that I will typically use in my direct testimony. In Case No. U-21870, the Company filed an updated version of the Reliability Roadmap as Exhibit A-129 (MPK-19). I am also sponsoring this updated 2025 version of the Reliability Roadmap in the instant case as Exhibit A-95 (EMD-11); the Company has not made any subsequent revisions since the filing of Case No. U-21870.

The 2025 version of the Reliability Roadmap defines the Company's current distribution objectives and goals, and the investment plans to meet those objectives and goals, which are reflected in the proposed spending levels in this case. The Company plans to file its next five-year distribution plan – which, per the Commission's guidance, will be titled the Distribution System Plan – by November 30, 2026, as required by the Commission in the July 10, 2025 Order in Case No. U-20147.

Q. What are the key objectives for the Company's electric distribution system in the Reliability Roadmap?

A. In the Reliability Roadmap, the Company has established four key objectives for its electric distribution system. These are as follows:

- **Safe** – The Company will continue to design and maintain its distribution system to ensure the safety and security of customers and employees is maintained and ultimately enhanced.

- **Reliable and Resilient** – To ensure system *reliability* during predictable weather variations under normal operating conditions, the Company will improve its capabilities and visibility to proactively operate the system and better manage power quality to provide customers with a grid that remains stable and available. To ensure system *resiliency* and performance, the Company will harden the system where necessary to withstand abnormal conditions driven by increasingly severe and unpredictable weather and climate events.

- **Clean and Equitable** – The Company is building a system that will be modernized, smart, and capable of accommodating changing customer technology adoption patterns, such as electric vehicles ("EVs") and distributed energy resources ("DERs"), for all communities served, ensuring members of disadvantaged communities have equitable opportunities to participate. The Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community—especially our most vulnerable—sees effective energy investment according to its needs, with minimal impact and energy burden.

Q. How will the Company achieve these objectives?

A. I will cover each of these objectives in the section of my direct testimony entitled *Vision for Electric Distribution*. In general, the Company plans to meet these objectives through the multi-year investment plan established in the Reliability Roadmap.

This investment plan incorporates a variety of best practices and forward-looking approaches to achieve reliability through increased line clearing, asset hardening, rehabilitation, and automation.

Critically, the Reliability Roadmap calls for increased investment in many of these high-impact work types, ramping up over several years. Beyond the investments in the Reliability Roadmap, the Company is pursuing other activities intended to meet one or more of the objectives, and I will discuss these efforts in the *Vision for Electric Distribution* section of this testimony.

Q. How did the Reliability Roadmap compare to prior strategies presented by the Company?

A. The Reliability Roadmap involved a continuation and an expansion of the Company's long-term distribution strategy of (1) excelling at the basics, and (2) building for the future by reasonably and effectively modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers today, and into the future.

When considering the electric distribution system, "excelling at the basics" consists of investments in and maintenance of core traditional infrastructure, like poles, wires, and substations, all of which improve electric system reliability under normal operating conditions, and resiliency under extreme conditions. The bulk of this work in reliability is concentrated in the Reliability Program and is explained in detail for LVD by Company witness Partlan, and for HVD by Company witness LaFrance.

"Building for the future" consists of enabling the transition to cleaner energy resources, including integration of DERs, and increasing automation of the system, using advanced grid technologies to provide the Company's customers with the technology and

tools to take greater control over their energy supply, reduce system waste, and optimize DER use. Testimony detailing this work is featured in Company witness Partlan's testimony on Conservation Voltage Reduction ("CVR") and LVD Lines Capacity, as well as Company witness McPhail's testimony on various Grid Automation initiatives.

Q. Please summarize the electric distribution plan in this filing.

A. In this filing, the Company is proposing to invest $1,460,571,000 in distribution system capital projects, and to spend $321,655,000 in distribution system O&M in the test year; as well as $1,782,975,000 in capital projects in the 16-month bridge period. This O&M spending is detailed later in my testimony, and includes programs related to line clearing, as discussed by Company witness Stewart, and to service restoration, as discussed by Company witness Dickey.

Line clearing and service restoration both make critical contributions to the Company meeting its electric distribution objectives. The Company's electric distribution system also includes streetlighting, which is addressed by Company witness Schmoekel.

Q. Which exhibits detail the capital for the bridge period and test year and the O&M for the test year?

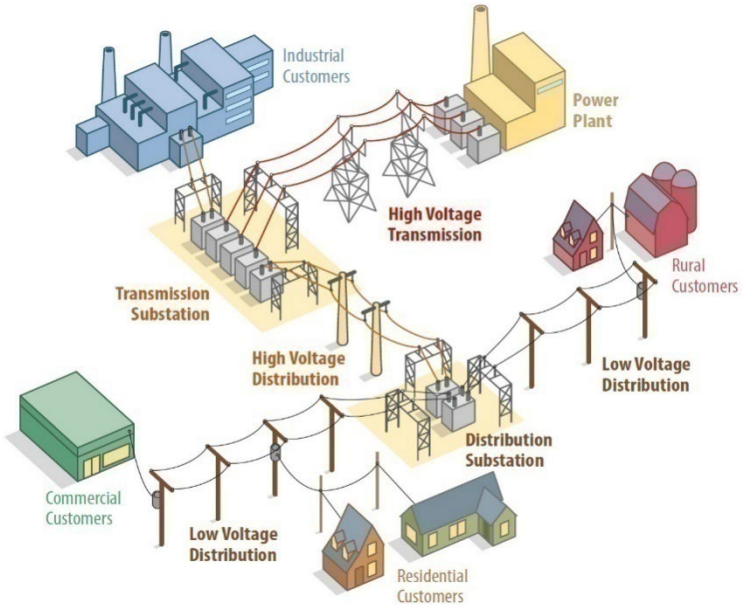
A. Capital spending for both the bridge period and the test year is outlined in Exhibit A-12 (EMD-1), Schedule B-5.6, through Exhibit A-88 (EMD-4). The O&M spending proposed for the test year is detailed in Exhibit A-89 (EMD-5) through Exhibit A-94 (EMD-10).

II. ELECTRIC DISTRIBUTION SYSTEM: OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. The Company's electric distribution system is comprised of the HVD, LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of more than 114,000 total miles of lines, made up of approximately 53,700 miles of primary overhead, 10,600 miles of primary underground, 31,300 miles of secondary overhead, and 18,600 miles of secondary underground.

The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number of and range of primary voltages differ because the Company acquired several distribution systems from smaller distribution companies throughout its history.

LVD primary voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 Volts and 480 Volts.

More than 2,000 LVD circuits serve the Company's 1.9 million electric customers, where a circuit is defined as a combination of electrical devices and hardware that are

connected and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.

The LVD system is expansive and subject to the greatest threat from common outage causes like trees, lightning, unexpected load increases, and third-party damage. It is largely a radial system that is not capable of continuing service to customers during outages. Company witness Partlan explains in her direct testimony how the Company is investing in the LVD system to provide reliability and resiliency of electric service to customers. Company witness Partlan also explains in her direct testimony how the Company is investing to convert, where possible, the LVD system from radial operation to looped operation through use of Automatic Transfer Recloser ("ATR") loops.

Q. Please provide an overview of the Metro system.

A. The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s through the 1950s to accommodate electric distribution in already busy downtown areas. Metro infrastructure is used, both in the past and today, to deal with the density of downtown city centers, facilitate electrical repairs, and for aesthetics.

The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited Right-of-Way ("ROW") in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower density areas. The Company's Metro planning group focuses solely on these key downtown areas.

Q. Please provide an overview of the HVD system.

A. The HVD system is composed of two primary areas—lines and substations. Consumers Energy's HVD system consists almost entirely of 46 kV lines and includes radial 138 kV and 69 kV lines. The HVD system is made up of approximately 140 substations that contain HVD assets, 4,900 miles of HVD lines, and 1,000 LVD substations.

The HVD system is considered the backbone infrastructure of the electric distribution system because it connects the electric transmission system to the Company's LVD system. The HVD system is largely a looped system that is capable of continuing service to customers despite the loss of any single component.

HVD investments are designed to ensure that the HVD system continues to provide a reliable backbone infrastructure critical to supplying the LVD system.

III. VISION FOR ELECTRIC DISTRIBUTION

Q. How is the Company's vision for electric distribution presented?

A. The Company's vision for electric distribution is presented primarily through its Reliability Roadmap, which was historically also known as the EDIIP. The third and most recent formal iteration of the Reliability Roadmap was filed with the Commission on September 27, 2023, and is the Company's articulation of its electric distribution strategy. This was updated in June 2025 as part of the filing of Case No. U-21870. The Reliability Roadmap is the underpinning document for the distribution plans laid out in this rate case.

Q. How has the Company's vision for electric distribution, as articulated in the Reliability Roadmap, evolved over the last several years?

A. The Commission first directed the Company to file a five-year distribution plan in an Order in Case No. U-17990, primarily to give the Commission visibility into how the Company made distribution investment decisions, and to provide a longer-term outlook into

investment plans beyond the single year contained in an electric rate case. In response to this Order, the Company filed its first EDIIP in March 2018.

A series of further Orders in Case No. U-20147 in 2018 through 2020 expanded Commission requirements for the Company's second EDIIP, which was filed in June 2021 ("2021 EDIIP"). The 2021 EDIIP addressed those expanded topical requirements and, in general, represented a continuation of the distribution strategies defined in the 2018 EDIIP.

Q. What happened following the 2021 EDIIP related to the Company's distribution strategy?

A. The Company (and other utilities in Michigan) experienced unusually severe storms in August 2021 that caused widespread outages, leading the Commission to initiate a thorough review of reliability in Case No. U-21122.

The Commission concluded that existing distribution investment plans were insufficient to ensure reliability in a world where increasingly severe weather is likely, and in September 2022, the Commission directed the Company to file a new distribution investment plan by September 30, 2023.[1] The Company duly filed its third EDIIP, the Reliability Roadmap, on September 27, 2023, in Case No. U-20147 ("2023 Reliability Roadmap").

In Case No. U-21870, the Company made minor amendments to the 2023 Reliability Roadmap. These amendments primarily concerned updating information to reflect another year of actual historical reliability data, and extending projected investments

[1] MPSC Case No. U-20147, September 8, 2022 Order, page 67: "[C]urrent approaches to distribution planning, the Commission finds, are insufficient to address issues impacting the reliability of utility to service to customers – whether current issues or those forecast for the future. Put bluntly, Michigan's distribution reliability is inadequate, and current plans for improvements are insufficient. Of paramount concern are continuing issues dealing with the safety and reliability of the system, including multiple fatalities within the month of August stemming from contact with downed wires as well as frequent and sustained outages stemming from storm events."

by another year into the future. Some content was also revised to reflect issues highlighted by intervenors in Case No. U-21585, or raised by intervenors in other regulatory areas, particularly in the Company's third-party distribution system audit conducted in Case No. U-21305. This amended version of the 2023 Reliability Roadmap is also included in the instant case as Exhibit A-95 (EMD-11).

Q. What differentiated the 2023 Reliability Roadmap from the first two EDIIP iterations?

A. In developing the Reliability Roadmap, the Company took to heart the Commission's findings on reliability, as identified in the September 8, 2022 Order in Case No. U-20147, particularly regarding the ability to improve reliability in the face of increasingly severe weather. To address those findings, the Company included more robust analysis of future reliability scenarios in its planning.

Consequently, the Reliability Roadmap evaluated multiple plausible future scenarios, including a future with increasing severity and frequency of storms, rather than assuming historical weather patterns will continue in the future. The Reliability Roadmap then laid out a multi-year investment plan to address asset deterioration and maintain asset health against identified risks while also hardening assets against increasingly severe weather, so that customer reliability improves even if conditions worsen.

Q. How did the Reliability Roadmap evaluate multiple plausible future scenarios?

A. In developing the Reliability Roadmap, the Company identified the factors that would most likely pose a future risk to the distribution system, with two major factors being identified:

a) increasingly severe weather; and

b) technological innovation driving increased demand on the grid, primarily distributed solar generation, EVs, and electrification of heating.[2]

The Company's analysis indicated the most significant weather-related risks are thunderstorms, other storms (i.e., extreme wind, ice storms), and high heat (which increases demand and increases line losses).[3]

Q. What scenarios did the Company develop for increasingly severe weather and for increased technological innovation?

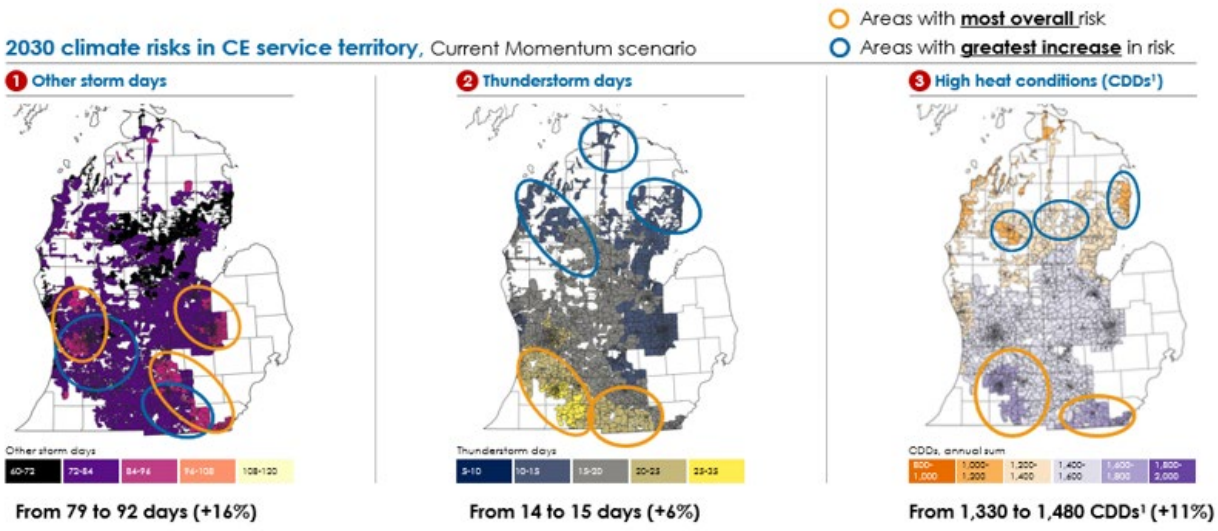
A. The Company developed three scenarios applicable to both major risk categories, called Decelerated Transition ("DT"), Continued Momentum ("CM"), and Accelerated Transition ("AT"), which are described in detail in the Reliability Roadmap.

Q. What conclusions can you draw from the Company's scenario modeling?

A. It is critical to note that, in any of the scenarios modeled, climate change will result in more severe weather and extreme heat, in turn creating increasing reliability and resiliency challenges for the distribution system. Regardless of climate policy, the Company's modeling projects an increase of 10-15% in severe weather-related outages by the early 2030s, compared to 2020 levels. The modeling also indicates load constraints due to electrification becoming a larger systemwide concern in the 2030s and 2040s, but this issue will remain localized to a small percentage of circuits for the remainder of this decade. *The most critical issue to focus on is reliability and resiliency in the face of storms, which is a more immediate threat.*[4] The projected impacts are graphically summarized in the Reliability Roadmap as shown in Figure 2 below.

[2] "Drivers of Change," Reliability Roadmap
[3] "Key Impacts Modeled," Reliability Roadmap
[4] "Impacts of Scenarios on the Distribution System," Reliability Roadmap

FIGURE 2
2030 CLIMATE RISKS IN CONSUMERS ENERGY SERVICE TERRITORY



This analysis aligns with the Commission's findings that previous distribution investment plans were not commensurate with the challenges posed by extreme weather.

Having performed this analysis in developing the 2023 Reliability Roadmap, the Company was better able to identify *where* increased investment is needed, *what kinds* of *investments* are needed, and *what levels of investment* are needed to harden the system and improve reliability for customers even as weather worsens.

As discussed further below in my direct testimony, the Company has, in developing the instant case, also evaluated other investment glide paths that could affect *what levels of investment* are planned on a year-by-year basis, building on a similar analysis presented in Case No. U-21870. These other evaluated glide paths follow recommendations in the Company's third-party distribution system audit conducted in Case No. U-21305. The Company has also evaluated these different levels of investment and their resulting glidepaths against the Commission's financial incentives and disincentives mechanism

targets, established through the Commission's February 27, 2025 Order in Case No. U-21400 and defined for the Company in Case No. U-21911.

Q. How does the Company intend to address the climate risks identified in the Reliability Roadmap?

A. In the face of these challenges, the Reliability Roadmap outlined the need to increase investment to develop a modern grid capable of mitigating the immediate threats from extreme weather. This was an increase, relative to prior investment levels, in the scale of established investments in infrastructure and spending on line clearing and inspections, while adding new types of resiliency investments.

Q. Can you explain the third-party audit of the Company's distribution system in Case No. U-21305?

A. On October 5, 2022, the Commission issued an Order in Case No. U-21305 that directed the Commission Staff to begin a third-party audit and review of all equipment and operations of the Company's distribution system and that of DTE. On July 11, 2023, the State of Michigan awarded a contract to perform the audit to Liberty Consulting Group ("Liberty"), following a public request for proposal process. Liberty was directed to file its report in late summer 2024. Over a period of many months, Liberty representatives met with key Company personnel to discuss the Company's distribution practices, and they visited different Company locations to study the state of the Company's distribution system. Liberty filed their report with the Commission on September 23, 2024, also in Case No. U-21305, and presented remarks and responded to questions during the Commission's open meeting on September 26, 2024. After providing for comments, the

Commission issued an order on June 12, 2025 in Case No. U-21305 adopting findings and recommendation of the Liberty report as discussed in the order.

Q. Do you wish to discuss any of Liberty's recommendations in your direct testimony?

A. In this direct testimony, I will specifically address audit issues with particular importance for the Company's distribution investment strategy. When the Company files its Distribution System Plan later in 2026, it will include detailed documentation of how Liberty's recommendations have been addressed.

Q. Which Liberty recommendations do you wish to address related to distribution investment strategy?

A. Liberty recommended the Company slow the pace of investment as defined in the 2023 Reliability Roadmap, and evaluate different timeframes for how the Company could meet its reliability goals. The 2023 Reliability Roadmap provided a System Average Interruption Duration Index ("SAIDI") glidepath that would result in second quartile SAIDI performance, excluding Major Event Days ("MEDs"), by 2029, or over approximately five years from when the Reliability Roadmap went into effect[5]. The Company agreed to supplement the five-year glidepath with seven-year and 10-year glidepaths for comparison, and did so in Case No. U-21870. The Company has further developed its comparison for the instant case, and this will be shown later in my direct testimony.

Liberty recommended the Company accelerate its forestry line clearing cycle so that the LVD system is on a four- or five-year cycle by 2028. The Company took this into

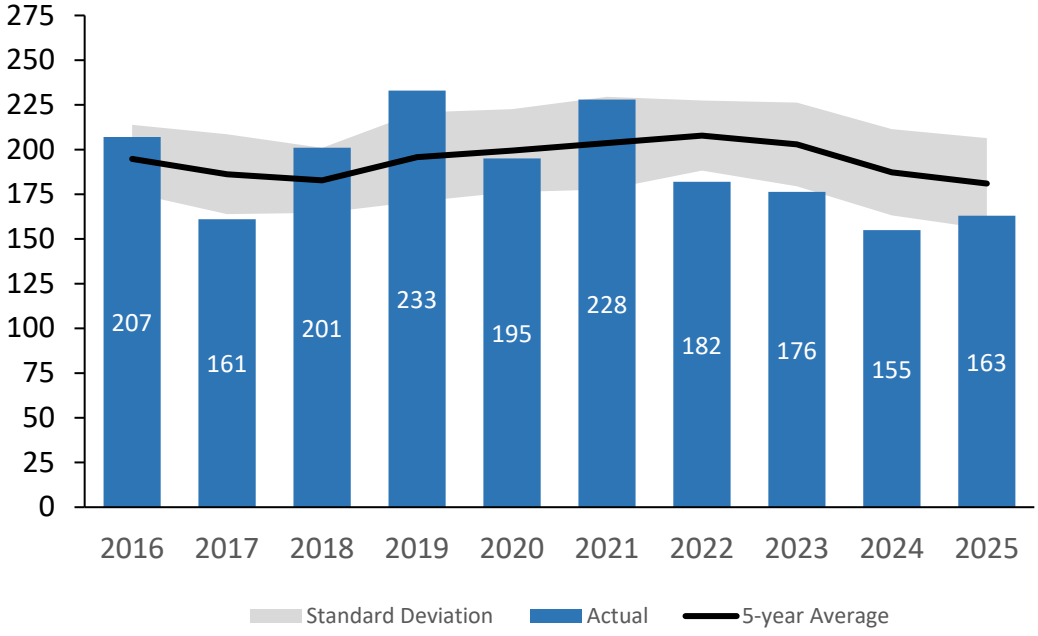
[5] For purposes of this discussion, the Company is using the Institute of Electrical and Electronics Engineers ("IEEE") quartiles, in which second quartile SAIDI excluding MEDs is better than or equal to 128 minutes based on the five-year historical average (2020-2024 Benchmark Results for 2019-2023 Data). IEEE updates its quartiles each year, meaning the thresholds can change, but this analysis assumes a constant 128 minutes.

account in Case No. U-21870, and proposed a five-year cycle, which the Commission approved. The Commission also directed the Company to further evaluate a four-year cycle in the instant case, which is addressed in more detail by Company witness Stewart. The increased forestry spending levels established in Case No. U-21870 have led to some adjustments in year-by-year capital investments relative to those proposed in the 2023 Reliability Roadmap, but do not eliminate the need for capital investments, as I will discuss later.

Q. What level of reliability has the Company's distribution system experienced in recent years?

A. I will present detail on recent reliability performance later in my testimony in the section on Historical System Performance. At a high level, the Company's distribution reliability showed worsening trends in later part of the 2010s, but has seen a significant improvement since 2021. These improvements began to take effect as the Company made initial increases in reliability investment following the development of the 2018 and 2021 EDIIPs. These trends are reflected in Figure 3 below.

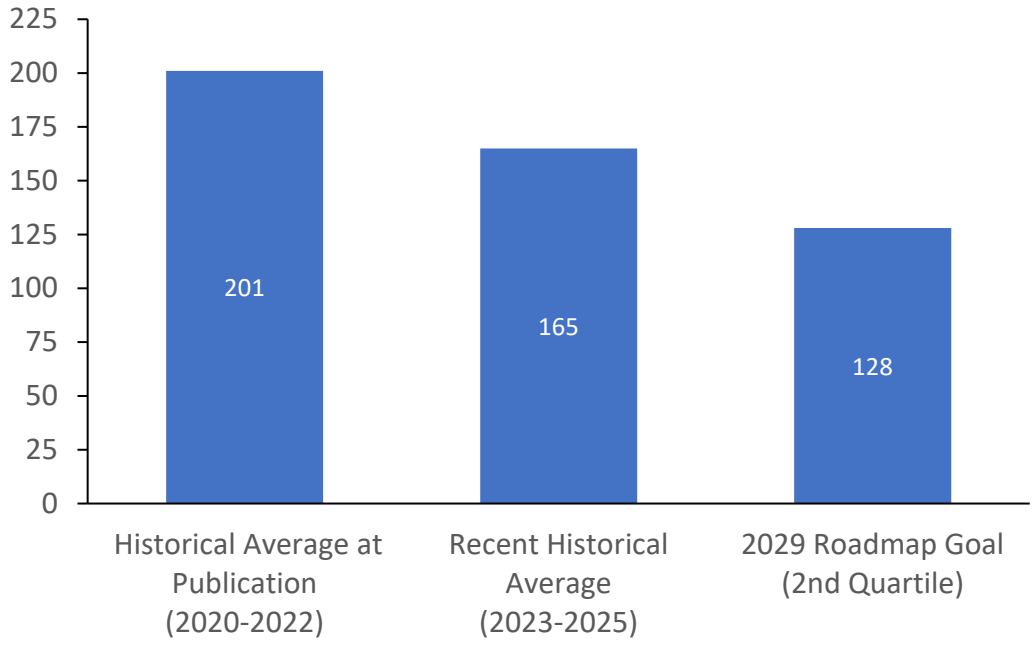
FIGURE 3
SAIDI PERFORMANCE COMPARED TO STANDARD DEVIATION (2016-2025)



Q. What benefits are the investments in the Reliability Roadmap designed to deliver for customers?

A. When the Reliability Roadmap was published in 2023, its investments were projected to deliver SAIDI excluding MEDs in the second quartile or better by 2029, or five years after investments began substantially ramping up. The Company maintains this goal of providing its customers with better than average reliability performance, and the Company has demonstrated clear improvement in delivering reliable service to its customers, having already closed nearly 50% of this gap in performance since the Reliability Roadmap's filing.

FIGURE 4
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



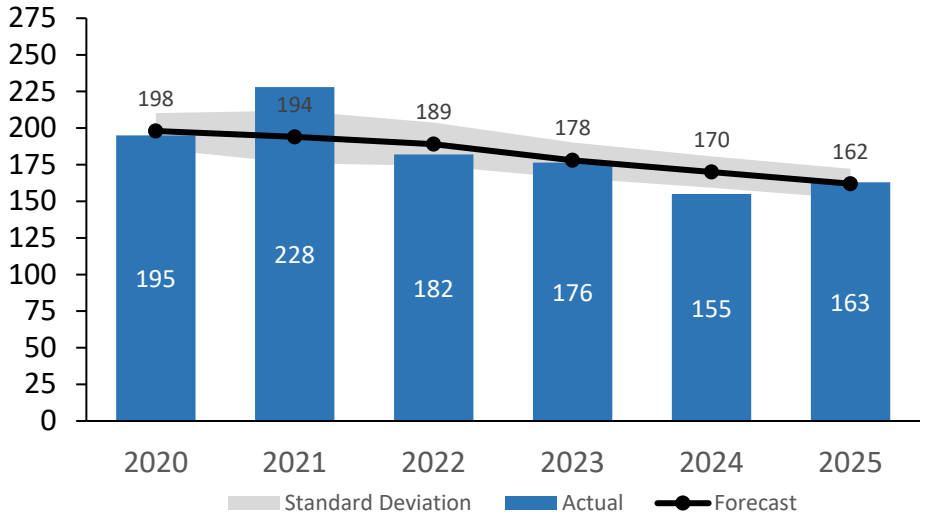
Q. How does the Company project this improvement in reliability performance?

A. The Company's model projects SAIDI, System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") based on historical relationships between these reliability metrics and forestry line clearing spending, capital investment in the distribution system, and certain CAIDI improvements. The model considers future projected forestry line clearing spending, capital investment in key areas, and CAIDI improvements and, in return, the model projects SAIDI, SAIFI, and CAIDI. This model does not incorporate all capital investment, but only those programs, sub-programs, and investment categories that have historically been shown to be most impactful on reliability metrics.

Q. What was the Company's SAIDI performance level in calendar year 2025 and how does this compare to the Company's SAIDI projection from the Reliability Roadmap?

A. The Company's SAIDI performance, excluding MEDs, was 163 minutes in 2025. The projected SAIDI performance for 2025 in the Reliability Roadmap, based on the proposed distribution capital investments, distribution O&M spending, and robust forestry line clearing plan was 162 minutes. While the Company's actual performance has differed slightly from what was projected in the Reliability Roadmap when it was first filed in 2023, as in 2021 and 2024, the Company expects actual performance to trend toward the projections, as with the results in 2022, 2023, and 2025. Variances are expected in projections, but the Company has confidence in its modeling of the glidepath given a total net variance over the past five years of eight minutes.

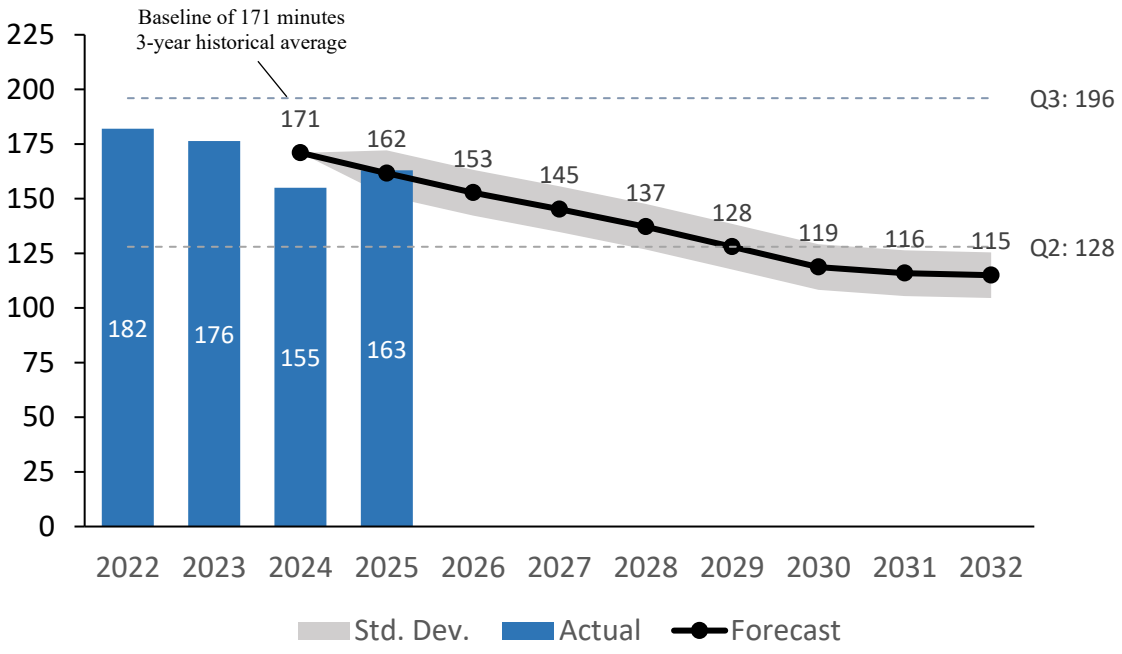
FIGURE 5
HISTORICAL SAIDI PROJECTIONS COMPARED TO ACTUAL



Q. What SAIDI performance level is projected to be produced through the spending outlined in this rate case?

A. The Company's projected glidepath for achieving second quartile reliability, as measured by SAIDI excluding MEDs, remains its primary goal through 2029, and the investments proposed in the instant case will keep the Company on this glidepath. The Company estimates full approval for the spending levels outlined in this case will put the Company on a glidepath to a SAIDI performance of approximately 128 minutes, excluding MEDs, by 2029, a reduction of 43 minutes from the 2024 baseline performance level of 171 minutes. The Company's requested distribution capital investments and distribution O&M spending, as well as the robust line clearing plan discussed by Company witness Stewart, support the planned glidepath to this improved SAIDI performance for customers.

FIGURE 6
SAIDI EXCLUDING MEDS PROJECTIONS



Q. Please provide more details on the Company's SAIDI glidepath.

A. Using the model described above, the Company's projections for SAIDI, SAIFI, and CAIDI are as shown in Figure 7 below. These figures are net of ongoing deterioration because a certain amount of investment is necessary to keep up with deterioration and to prevent performance from worsening.

FIGURE 7
RELIABILITY PERFORMANCE GLIDEPATH

	Baseline	2025	2026	2027	2028	2029
Net SAIFI	0.93	0.89	0.85	0.82	0.79	0.75
Net CAIDI	184	181	179	177	174	172
Net SAIDI	171	162	153	145	137	128

Q. What Company investments and activities will support this improvement in SAIFI?

A. The Company's model indicates certain investments and activities proposed in this filing will affect SAIFI, as shown in Figure 8 below.

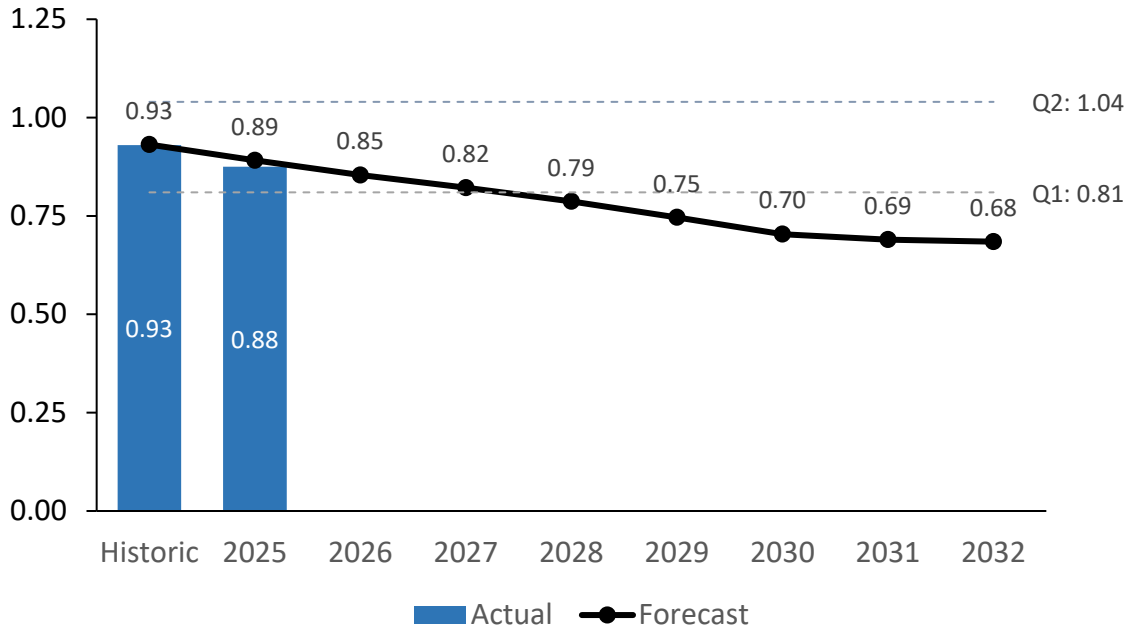
These figures are also net of ongoing deterioration. In some areas, shown as negative numbers, the Company's investments and activities will drive a net reduction in SAIFI over the glidepath period.

In other areas, shown as positive numbers, SAIFI will increase on net due to deterioration; however, the Company's investments in these areas are still necessary to prevent SAIFI from getting even worse. The figures shown for each year are cumulative, not incremental.

FIGURE 8
SAIFI GLIDEPATH IMPACT BY INVESTMENT/ACTIVITY AREA

Investment Category	2025	2026	2027	2028	2029
Line Clearing	(0.003)	(0.008)	(0.018)	(0.035)	(0.063)
Security Assessment Repairs	(0.017)	(0.033)	(0.048)	(0.061)	(0.073)
Zonal Health Projects	(0.024)	(0.042)	(0.050)	(0.057)	(0.063)
Fractionalization	(0.007)	(0.011)	(0.015)	(0.019)	(0.023)
Vulnerable Communities	(0.000)	(0.002)	(0.003)	(0.004)	(0.005)
LVD Pole Replacements	0.001	0.001	0.002	0.002	0.003
ATR Loops	(0.003)	(0.007)	(0.009)	(0.010)	(0.011)
Undergrounding	(0.000)	(0.001)	(0.004)	(0.006)	(0.008)
HVD Pole Replacements	(0.000)	(0.001)	(0.001)	(0.0000)	(0.000)
HVD Pole Top Rehabs	(0.000)	(0.001)	(0.002)	(0.003)	(0.004)
HVD Line Rebuilds	(0.000)	(0.002)	(0.005)	(0.007)	(0.009)

FIGURE 9
SAIFI GLIDEPATH

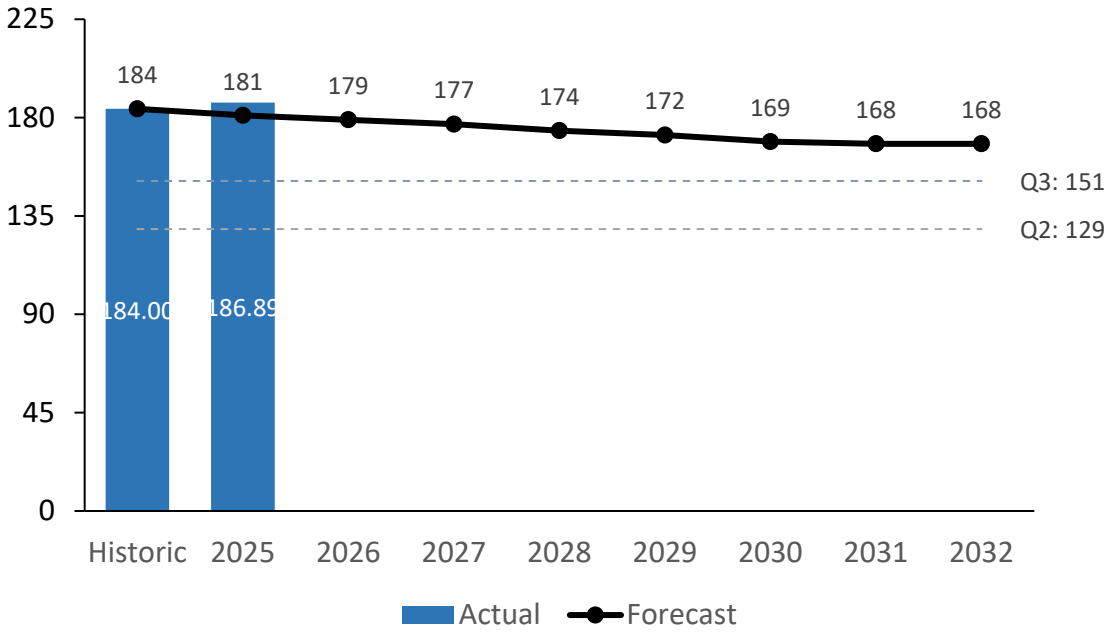


Q. What is the CAIDI glidepath?

A. The Company's model indicates that certain investments and activities proposed in this filing will affect CAIDI, as shown in Figure 10 below.

As the number of outages is reduced, crews will have fewer outages to respond to; this reduction in workload will allow crews to more quickly address outages that do occur. This will produce CAIDI savings.

FIGURE 10
CAIDI GLIDEPATH



Q. What else will the investments identified in the Reliability Roadmap address?

A. Some investments identified in the Reliability Roadmap are also intended to address asset health risk.

In these situations, assets may not be experiencing poor reliability today, but the Company has assessed that these assets are in poor health and at heightened risk of failure in the near future. Investing in these assets will make the system more robust.

Company witnesses Partlan and LaFrance both identify various investments related to asset health risk. Although asset health risk applies to all Company infrastructure to some extent, the issue is most prominent when considering the HVD system, substations, and Metro infrastructure.

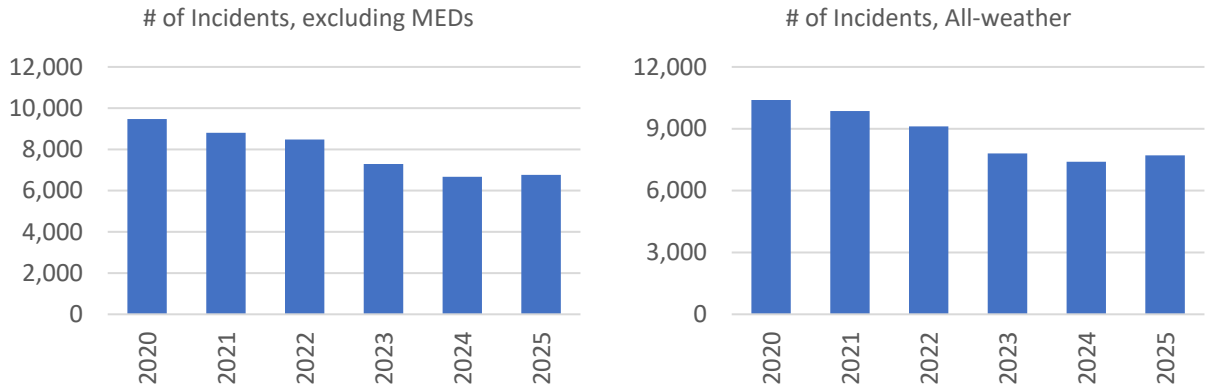
Q. If the Company is increasing its line clearing, why are increased capital investments still needed?

A. Although line clearing is an important part of how the Company is working to improve reliability, line clearing alone is not sufficient. For one thing, systemwide line clearing benefits will take time to materialize even as the Company begins shifting to a five-year clearing cycle. Conversely, capital investment in the distribution system has already begun delivering reliability benefits. The Company began earnestly ramping up distribution investments from 2018, when the first EDIIP was filed, and the Company began experiencing a clear downward trend in equipment failures starting in 2020, only two years after beginning increased investment. Equipment failure has been a significant contributor to SAIDI in its own right (see Figure 37 later in this testimony). This downward trend continued through 2024, as shown in Figure 11 below, indicating that investments identified in the 2018 and 2021 EDIIPs were well-targeted and quickly delivered benefits. The downward trend leveled off in 2025, indicating that the benefits from the 2018 and 2021 EDIIPs have likely leveled off as well; as the investments identified in the 2023 Reliability Roadmap begin to take effect, the Company expects to continue driving the rate of equipment failures down, which should work in conjunction with increases in forestry work.

This leveling off in 2025 was also attributable to the specifics of the storms that took place. As Company witness Dickey explains in his direct testimony, the ice storm in northern Michigan in March/April 2025 was the worst ice storm in Michigan in over a century, causing a significant number of equipment failures due to ice accumulation. 2025 was also one of the worst years for tornadoes in Michigan in the last several decades. These

storms further reinforce the Company's need to invest in its distribution system to harden against the increasing frequency of these events.

FIGURE 11
EQUIPMENT FAILURES (2020-2025)



Even as the Company increases its line clearing activity, trees will still fall on LVD lines and impact the distribution system. Trees are living organisms that are always changing. A tree that poses no threat today may become a hazard before the next clearing cycle (conversely, new assets do not begin to deteriorate to the point of failure for a much longer period of time). The Company's investments in hardening the system will reduce the number of customer interruptions and/or make the interruptions shorter, countering the impacts trees have on the system.

FIGURE 12
HEALTHY, OUTSIDE RIGHT OF WAY TREE IMPACTING DISTRIBUTION SYSTEM[6]



Q. As the Company increases planned line clearing, has it made any adjustments to its capital investment plan?

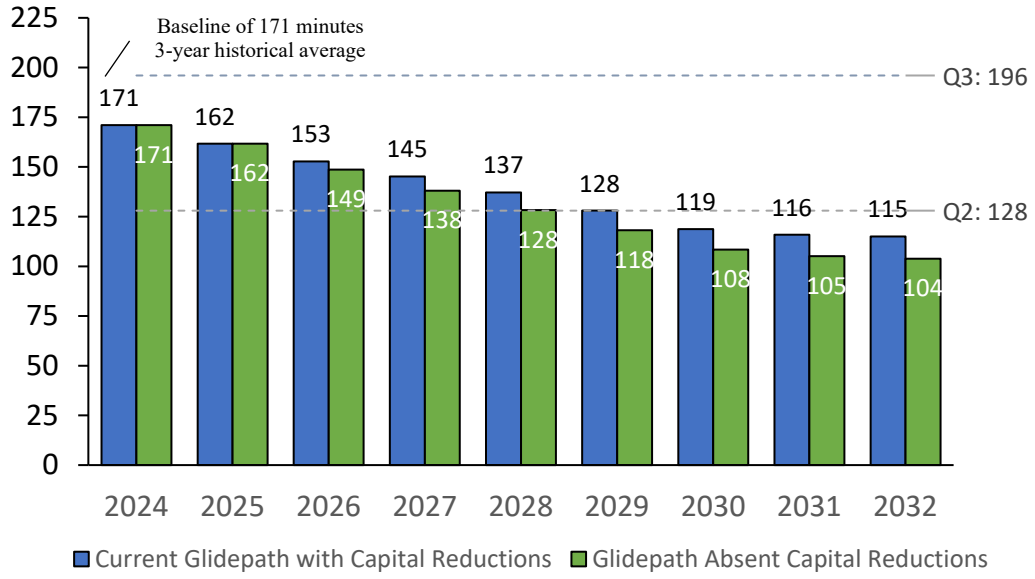
A. Yes. The Reliability Roadmap, when first filed in 2023, presented a plan to ramp up investments to address 280 zones each year on the LVD system. This ramp-up formed a critical component of the Company's projected SAIDI glidepath as it was laid out in the Reliability Roadmap. Since the Company is now pursuing a more aggressive line clearing strategy, the SAIDI glidepath modeling discussed above indicates the Company does not need to ramp its zonal health work up as significantly. With the current line clearing plan, the Company only needs to address 85 zones per year. This change in the number of zones addressed results in an $80 million reduction in capital that otherwise would have been requested by the Company.

[6] Photo taken on 8/7/2015 conveying damage to Company's system - substation and circuit were not noted.

Q. What would have been the Company's reliability performance had the Company not made changes to its capital investment plan given the increase in line clearing?

A. Had the Company not made the previously mentioned adjustment to the capital plan, the Company would have been able to achieve the Reliability Roadmap goal of second quartile SAIDI a year earlier than originally outlined in 2028 as shown below. The Company maintains that its original timeline to achieve second quartile reliability is reasonable.

FIGURE 13
SAIDI PROJECTIONS WITH INCREASED LINE CLEARING



Q. Has the Company considered alternatives in developing the Reliability Roadmap and the investment plan contained therein?

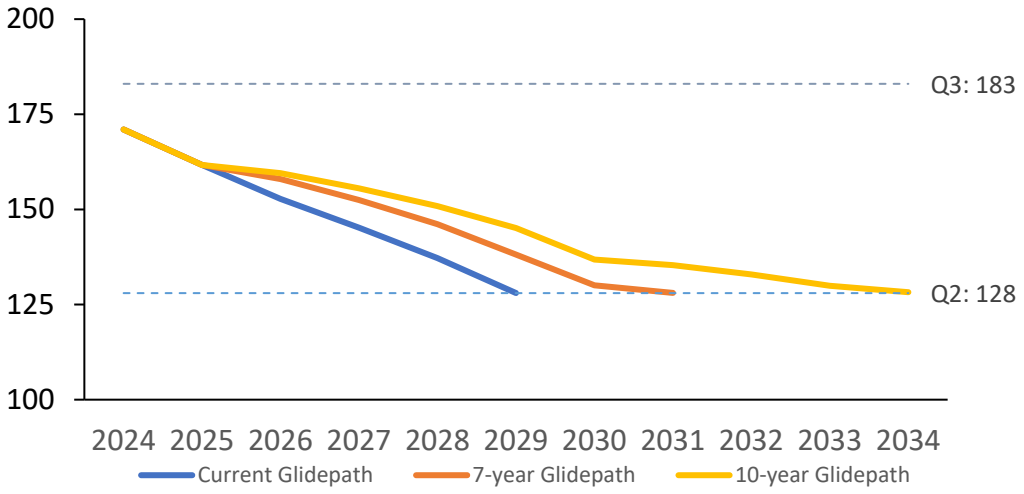
A. Yes. There are two different ways the Company considered alternatives in the context of distribution planning. First, we considered alternatives to the Reliability Roadmap as a whole: Are there alternatives to investing in the entire portfolio of assets laid out in the Reliability Roadmap, and at the levels included in the Reliability Roadmap? Second, we considered alternatives to individual projects: Is the Company prioritizing its investments

and choosing the best options to address identified issues on the system? I will address the first of these concerns directly below. I will address the second concern regarding how the Company chooses the right projects, later in my testimony in the Capital Spending Overview section.

Q. What alternatives has the Company considered regarding the overall scope of investment laid out in the Reliability Roadmap?

A. As noted above, the Reliability Roadmap would put the Company on track to providing second quartile SAIDI excluding MEDs by 2029. Based on Liberty's recommendation, the Company has also modeled what it would look like for the Company to slow its pace of investment and reach that SAIDI target over seven or 10 years. The difference between the Reliability Roadmap and these alternative slower glidepaths is illustrated in Figure 14 below.

FIGURE 14
Q2 RELIABILITY GLIDEPATHS



Q. How would these slower glidepaths impact capital investment in the system?

A. These slower glidepaths would nearly eliminate the most beneficial reliability and resiliency programs for the LVD system. The seven-year glidepath would further reduce

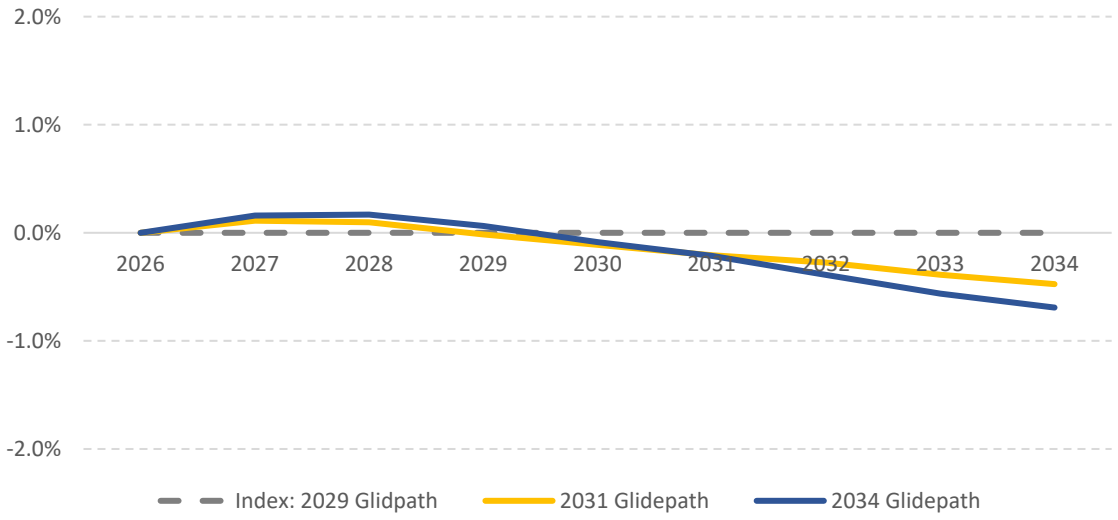
the number of equivalent zonal health projects to 25 per year, and reduce the investment in ATRs from 30 Loops to 10 Loops per year. The 10-year glide would completely eliminate investment in zonal health projects and ATR Loops. These plans would reduce capital by approximately an additional $35 million a year for the seven-year glidepath and approximately $50 million a year for the 10-year glidepath.

Q. How would these slower glidepaths impact rates and affordability?

A. By slowing the glidepaths in achieving second quartile SAIDI excluding MEDs to 2031 or 2034, the Company estimates that the average residential distribution rate would be reduced by less than 1% from that forecasted in achieving second quartile by 2029. The alternate glidepaths could result in residential customers paying more in the near-term as shown in Figure 15 for worse reliability as depicted in Figure 14 Ultimately, the impacts of the alternate glidepath would result in a change in energy burden of less than 0.02% through 2034.

FIGURE 15

PERCENTAGE CHANGE IN AVERAGE RESIDENTIAL DISTRIBUTION RATE OF ALTERNATIVE GLIDEPATHS



Q. Are there any other concerns if the Company were to reduce its investments to align with either of these alternative glidepaths?

A. These alternative glidepaths would also result in the Company having a less diverse portfolio of reliability investments.

With the near or full elimination of investments in targeted zones, ATR Loops, and Fractionalization, the Company would be overly reliant on line clearance to achieve its targeted performance.

Q. Why does the Company believe it is important to invest at levels that will deliver second quartile SAIDI by 2029?

A. Pre-Reliability Roadmap investment levels would have led to gradual improvements in SAIDI performance, but even by the end of the decade the Company's SAIDI performance would still be in the middle of the third quartile. Likewise, the slower glidepaths suggested by Liberty would leave the Company's performance lagging in the third quartile until well into the next decade. Customers will benefit from the Company's plan for more rapid improvement in reliability.

Q. Why does the Company believe it is important to deliver better-than-average reliability to customers?

A. First and foremost, the Company is fundamentally committed to delivering reliable electric service to its customers as a core business principle. Other parties have also indicated a need for improved reliability.

For example, the Citizens Utility Board of Michigan ("CUB"), a regular intervenor in the Company's rate cases, including in Case No. U-21870, publishes an annual "Utility Performance Report" that assesses Michigan utilities by a variety of measures, including

reliability. In their 2025 edition of the Utility Performance Report, CUB states in the report overview that "The five-year averages for Michigan utility reliability performance metrics continue to be among the worst in the country and the worst of any Great Lakes state," and "As the climate continues to warm, Michigan's utility customers will suffer increasingly from long outages unless the utilities invest in effective outage prevention and response measures."[7] CUB's emphasis on poor reliability in their Utility Performance Report is typical of the statements made by other parties about reliability in regulatory proceedings before the Commission, indicating that this is an ongoing issue, and indicating a consistent demand for significant improvement in reliability.

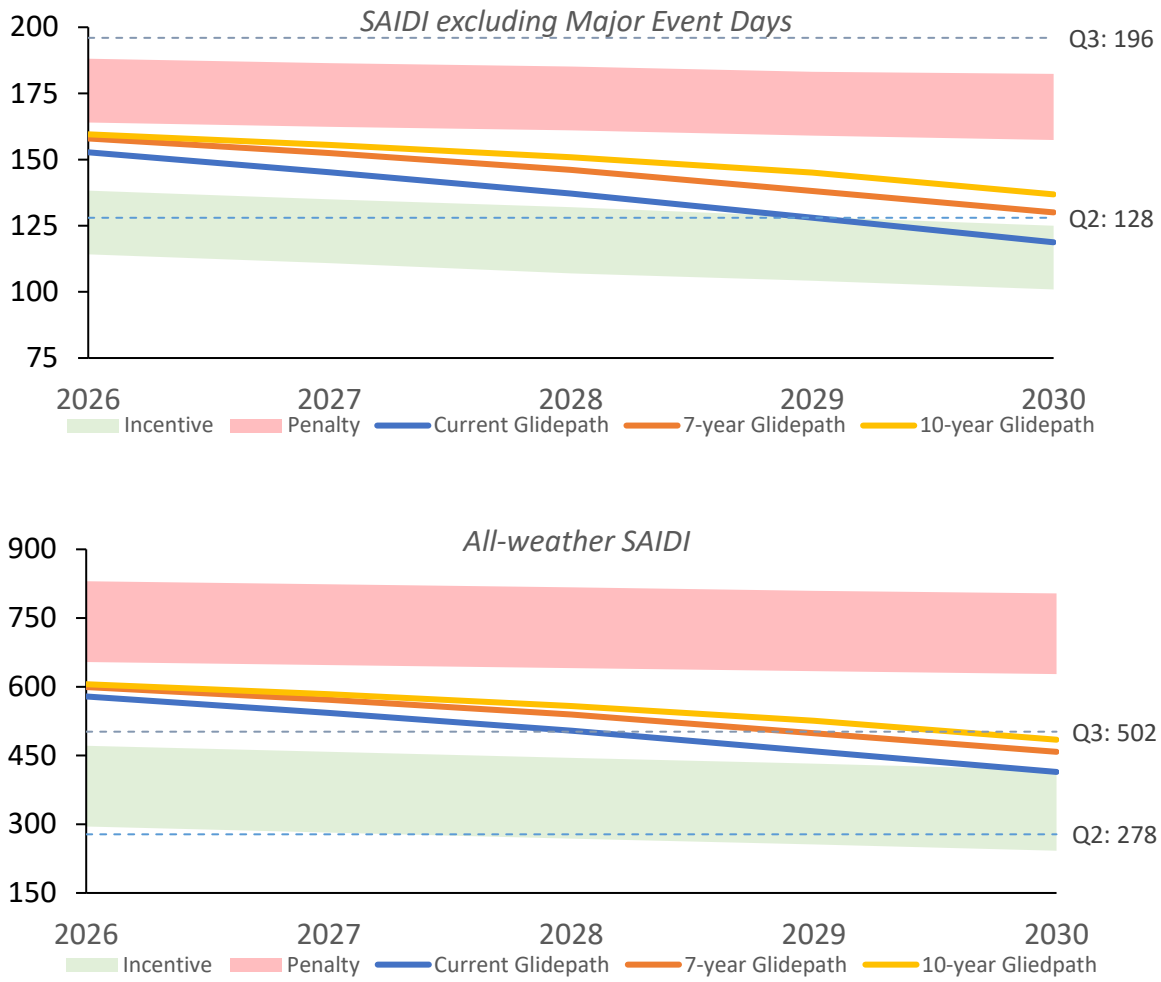
To cite another example, the Michigan Department of Attorney General routinely calls for improved reliability and maintains a website[8] that seeks to collect power outage data.

Q. How do the glidepaths compare to the targets established through the Commission's financial incentives and disincentives mechanism in Case No. U-21400?

A. This mechanism is commonly referred to as performance-based ratemaking ("PBR"). The Company's PBR targets were formally set in the Commission's December 18, 2025 Order in Case No. U-21911. In Figure 16 below, the Company has compared its projected performance glidepaths for two of the PBR metrics under the Reliability Roadmap and both of Liberty's more gradual approaches, against the targets based on the December 18 Order.

[7] Available at https://cubofmichigan.org/wp-content/uploads/2025/09/2025-Utility-Performance-Report_20250904.pdf.
[8] https://www.michigan.gov/ag/initiatives/utilities

FIGURE 16
PBR METRICS – GLIDEPATHS COMPARED TO TARGETS



Q. Is there a method for calculating a quantitative benefit from the implementation of the Reliability Roadmap?

A. Based on the Interruption Cost Estimate ("ICE") Calculator tool developed by Lawrence Berkeley National Laboratory and Resource Innovations, and funded by the Energy Resilience Division of the U.S. Department of Energy's ("DOE") Office of Electricity, the Reliability Roadmap SAIDI projection will yield up to $2.7 billion worth of benefits in avoided outage costs.

Q. Has the Company considered other means to achieve similar reliability improvements as those projected in the Reliability Roadmap without the associated increase in capital investment?

A. The Company believes the investments and spending projected in the Reliability Roadmap represent the right mix of work to deliver improved reliability.

Taking into account recommendations from the distribution audit and considering additional data analysis and information that has become available, the Company is ramping up to a five-year LVD line clearing cycle, with a plan to be fully on-cycle by the end of the 2030-2031 test period.

The Company is also performing more aggressive line clearing through canopy removal on targeted three phase primary sections of circuits. Company witness Stewart discusses this line clearing vision in her direct testimony.

Q. What other alternatives to capital investment exist besides line clearing?

A. Various parties provided comments on the Reliability Roadmap in Case No. U-20147 in February 2024.

Some comments stated the Company might have used the Reliability Roadmap to give more consideration to non-wires alternatives ("NWAs," sometimes also referred to as non-wires solutions, or "NWS"), suggesting that DERs and other approaches could be used to deliver reliability benefits. Similar arguments were made by some intervenors in Case Nos. U-21585 and U-21870. I will address that suggested approach below.

Additionally, the Company could consider the alternative of simply letting more assets run to failure rather than identifying asset health risks and proactively addressing them. But this would do nothing to improve reliability; when assets fail, customer

interruptions are common, so running assets to failure as a matter of choice would lead to worse reliability. Furthermore, reacting to failures is more expensive than proactively addressing issues in a planned way, a phenomenon seen across the industry. For example, the Company's internal crew labor rates are double during storm responses compared to the straight-time rates used for planned work.

Q. Please summarize the Company's views on NWAs.

A. NWAs may be a viable option to improve distribution reliability, and the Company has studied the potential of NWAs in pilots in the last decade, which were discussed in detail in the 2021 EDIIP. At that time, the Company had recently completed two NWA pilots. The results of these pilots from 2017-2018 and 2019-2021 showed that successfully deploying NWAs on the Company's system and generating benefits from those NWAs would prove difficult. In short, the Company's findings were that, for even a relatively limited use case such as deferring an LVD substation capacity upgrade:

a) significant lead time was needed to procure the non-wires resources;

b) benefits in one case were unclear; and

c) benefits in another, while theoretically possible, were insufficient when one or two large customers introduced new load.

Using NWAs to deliver reliability benefits, as opposed to capacity benefits, requires more certainty about deployment schedule and actual reliability parameters. As far as the Company is aware, no U.S. utility to date has developed an NWA that works as an off-the-shelf solution to improve distribution reliability.

Q. Is the Company considering NWAs in any other contexts at this time?

A. The Company believes its conclusions to date are valid, but it is possible that other approaches besides those used in earlier Company pilots could prove viable. Therefore,

the Company is working to develop a new NWA pilot, to be proposed outside of the regular rate case process using the expedited pilot process the Commission created in its February 23, 2023 Order in Case No. U-20898. According to the terms of the approved process, the Company began meeting with stakeholders on January 21, 2026 to seek input, with a goal of filing a proposal as soon as practicable through the approved process.

Additionally, Company witness McPhail describes how the Company is evaluating Virtual Power Plants ("VPPs") as part of the DER Optimization initiative in response to the Commission's Order in Case No. U-21870.

Q. Is the Company aware of any ongoing industry trends regarding NWAs?

A. Many theoretical NWA applications rely on some kind of use of DERs to defer distribution investments. Beginning in 2018, the State of California implemented a Distribution Investment Deferral Framework ("DIDF"), which established a three-year planning process to identify and implement opportunities to use DERs to defer distribution upgrades. This process began with load and DER forecasts, proceeded through identifying deferral opportunities and soliciting deferral projects, and finally awarding contracts. To date, this represents one of the very few attempts to promote NWAs at widespread scale.

Q. What happened with the DIDF in California?

A. In December 2025, the Electric Power Research Institute ("EPRI") published the results of a study into the ability of DERs to provide grid benefits through the DIDF[9]. The study notes that, "From the beginning… the framework struggled to consistently procure DER-provided distribution services as viable alternatives to traditional grid upgrades." Despite various attempts at reform, the California Public Utilities Commission ultimately

[9] EPRI's study is publicly available at: https://www.epri.com/research/products/000000003002034025

suspended the core of the DIDF in 2024. Over the course of seven annual planning cycles, utilities issued 112 solicitations for proposals to address distribution deferral opportunities. Of these, only 10 resulted in the award of a contract, and to date only three are operational. Despite various reforms in 2019 through 2021, the DIDF struggled to attract proposals that were both technologically feasible and economically competitive, even with the utilities being mandated to identify opportunities where DERs may have been helpful.

Q. What factors contributed to the DIDF's challenges?

A. According to the EPRI study, there were two major issues. First, DER developers were unable to make economically competitive offers that were capable of deferring traditional grid investments. DER-based NWA use cases depend on the idea that the selected technology represents savings when compared to simply upgrading the grid; if the DER is not actually cheaper, then the purported benefit to the grid does not really exist. Second, load growth – tied in this case to California's electrification goals – requires utilities to further build out grid infrastructure, such that deferring investment is not technologically feasible or is counterproductive. This second issue resonates with the Company's 2020-2021 NWS pilot based on using targeted demand response to defer a substation capacity upgrade at its Four Mile substation in Grand Rapids. In that instance, the near-term emergence of a large commercial development meant that the Company had to build a new substation even when the demand response was accounted for.

Q. What conclusions can be drawn from the DIDF?

A. The results in California show that using DERs as NWA to solve distribution issues is difficult, and even with thoughtful, commission-led program design over multiple years, there is no guarantee that DERs will in fact deliver those solutions.

Q. Why is the Company pursuing its NWA pilot considering the DIDF?

A. California's experience does not necessarily mean that NWAs are always infeasible; this is why the Company is pursuing another NWA pilot, to investigate the extent to which DERs may provide benefits on the Company's system, and why it is important to have patience with the pilot process.

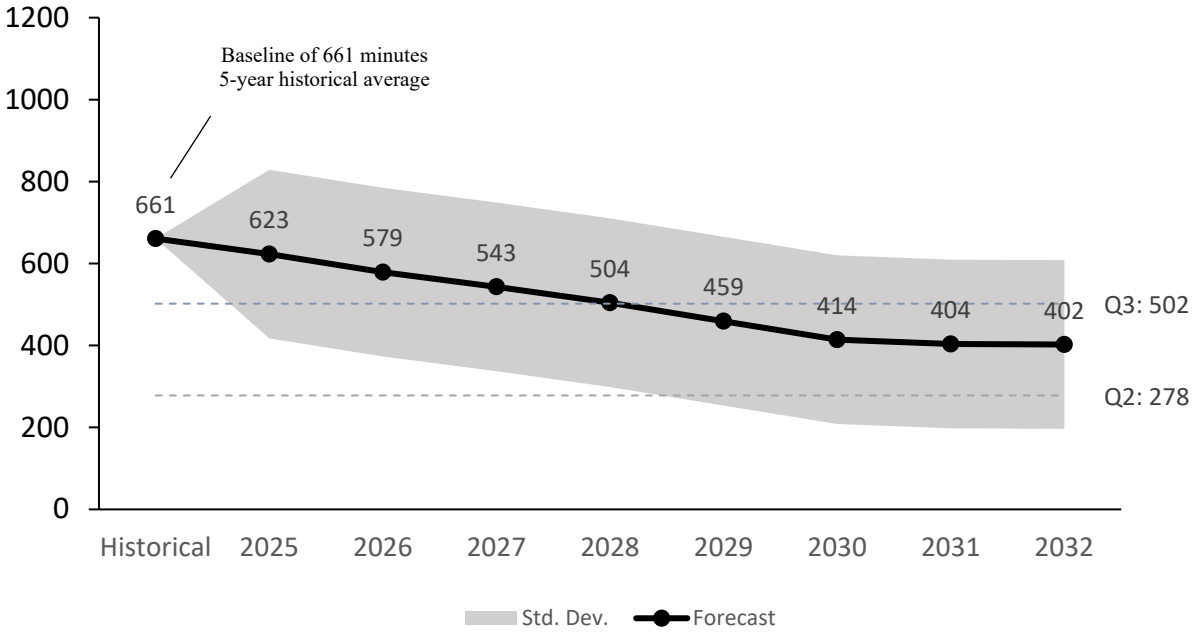
Q. Is the Company considering strategies to address reliability metrics other than SAIDI excluding MEDs?

A. Yes. Although the Company gives significant focus to SAIDI excluding MEDs, since it is defined by IEEE and used as an industry-standard metric, the Company understands that other metrics are also relevant. SAIDI including MEDs, or all-weather SAIDI, is important to consider as it reflects the real day-to-day experiences of customers. The Company has already been working to better address all-weather SAIDI, which requires investments to improve resiliency as well as reliability.

In Case No. U-21224, filed in 2022, the Company first introduced its Resiliency investment category as an early step to specifically target all-weather SAIDI. In Case No. U-21389, the Company first proposed an Investment Recovery Mechanism ("IRM") with an explicit goal of supporting investments designed to reduce the occurrence of MEDs (see more discussion later in my direct testimony on the IRM). In Case No. U-21870, the Company proposed a new Vulnerable Communities Resiliency Plan (also discussed later in my direct testimony) with a goal of getting communities in economically vulnerable areas into the second quartile of all-weather SAIDI. Furthermore, the Commission has established all-weather SAIDI as a metric for its new PBR framework in Case No. U-21400; as the PBR framework is fully implemented, the Company expects to develop

even more investments intended to improve all-weather SAIDI and meet the Commission's expectations.

FIGURE 17
ALL-WEATHER SAIDI PROJECTIONS



Finally, the Company has not met the Commission's Service Quality and Reliability Standards for Customers Experiencing Multiple Interruptions-4 ("CEMI-4") in recent years. CEMI-4 has also now been designated as a metric in the PBR framework. To meet the Commission's standards for CEMI-4, and to respond to the Commission's PBR targets, the Company is increasing its investments in its LVD Repetitive Outages sub-program, as discussed by Company witness Partlan, to specifically target this metric.

Q. How is this rate case tied to the Company's Reliability Roadmap?

A. In short, the overall distribution plan outlined in this electric rate case corresponds with what was presented in the Reliability Roadmap in terms of investments and work activities that will take place during the bridge period and test year; as noted above, the updated 2025

version of the Reliability Roadmap included in the instant case as Exhibit A-95 (EMD-11) includes some amendments that differ from what was filed in September 2023.

While the Reliability Roadmap lays out a distribution strategy and investment plan over multiple years, this rate case translates particular years of that investment plan into specific investment programs, sub-programs, investment categories, and projects.

Q. Is the instant case exactly aligned with the 2025 version of the Reliability Roadmap?

A. While the instant case corresponds with the 2025 Reliability Roadmap, there are some differences. The distribution system plan filing guidelines approved in the Commission's July 10, 2025 Order in Case No. U-20147, Exhibit A, state that "A utility requesting rate relief before the Commission must provide, within testimony or as an attachment or an exhibit to that filing, a supplemental to its most recent [distribution system plan] and its ongoing implementation."

Q. What supplemental information are you providing in the instant case?

A. Exhibit A-103 (EMD-19), which was also provided as Part III Requirement Attachment #170, provides a summary of the dollar amounts in the 2025 Reliability Roadmap that correspond to the bridge period and test year in the instant case, with comparisons to the amounts proposed by the Company in the instant case. For many line items, the 2025 Reliability Roadmap amounts and the amounts proposed in the instant case differ only moderately, and would be explained simply by the relatively general cost estimates in the 2025 Reliability Roadmap being updated as specific projects are identified and designed. In a few instances, the differences are more significant, as follows:

- Targeted Circuit Improvements are lower in the instant case than in the 2025 Reliability Roadmap. This is driven primarily by a reduction in planned investment for underground cable injection, as explained by Company witness Partlan.

- LVD Pole Replacements are lower in the instant case than in the 2025 Reliability Roadmap. This is driven primarily by a) the Company experiencing a lower pole rejection rate than assumed in the Reliability Roadmap, and b) the Company's decision to not replace poles solely based on age. This is explained by Company witness Partlan.

- The Resiliency sub-program's investments are lower in the instant case than in the 2025 Reliability Roadmap. This is driven by adjustments to the Company's plan for overhead-to-underground conversions. Disallowances for this work in Case No. U-21585 and Case No. U-21870 led the Company to delay its overhead-to-underground ramp-up plan as presented in the 2025 Reliability Roadmap.

- LVD Lines Capacity is lower, for the bridge period, in the instant case than in the 2025 Reliability Roadmap. Disallowances for this work in Case No. U-21585 and Case No. U-21870 led the Company to push back its planned ramp-up in LVD Lines Capacity.

- Substation investments – particularly HVD Substations Reliability, Transformer Bank Replacements and Substation Rebuilds, and LVD Substations Reliability and Rehabilitation – differ in the instant case from the levels in the 2025 Reliability Roadmap as the Company adjusts its workplan in response to disallowances in Case No. U-21870.

- HVD Strategic Customers New Business differs in the instant case from the 2025 Reliability Roadmap due to the unique nature of the sub-program, which is discussed in detail by Company witness LaFrance. Investment levels for future years in this sub-program, as presented in the 2025 Reliability Roadmap, were based on known projects and projections of future emergent projects, but this always has the potential to be variable as customer plans change.

- The Company's needed workforce resources in the instant case, sponsored in the direct testimony and exhibits of Company witness Rachel R. Babale, differ from those presented in the 2025 Reliability Roadmap. Specifically, Company witness Babale presents LVD and HVD resource needs in 2026, 2027, and 2028 that are lower than those shown in the 2025 Reliability Roadmap. These lower resource needs are partially attributable to the adjustments to the capital workplan discussed above; they are also the result of adjustments made by the Company when it moved forward with planning the specific work and improved its understanding of specific needs.

Q. Can all of the distribution investment included in this electric rate case be found in the Reliability Roadmap?

A. No. The Reliability Roadmap focused on strategic investments needed to improve reliability and resiliency and/or address asset health risk. Investment not related to these objectives, particularly in the New Business, Asset Relocations, and Demand Failures programs were not discussed in significant detail in the Reliability Roadmap.

Q. Does the Reliability Roadmap establish any other fundamental building blocks of distribution strategy?

A. Yes. The Reliability Roadmap also states the four distribution objectives that I defined in the Executive Summary of this direct testimony: Safe, Reliable and Resilient, Clean and Equitable, and Competitive. Taken altogether, these provide the Company with a comprehensive distribution strategy. I will explain specific activities designed to meet these objectives later in this direct testimony.

Q. Are there any other factors that affect the Company's electric distribution strategy?

A. Yes. While the Company is building for the future of the electric distribution grid, it is simultaneously supporting the Company's 2021 Integrated Resource Plan ("IRP").

Q. Please explain how the 2021 IRP informs the Company's distribution strategy.

A. The IRP relied on the use of CVR, discussed in greater detail in the direct testimony of Company witness Partlan, to reduce generation needs as a means of addressing the Company's electric capacity requirements. The CVR investments discussed by Company witness Partlan represent a continuation of this component of the IRP.

Objective: Ensure safety and security

Q. How do the Company's proposals in this case support the Company's objective to ensure safety and security to workers and the public?

A. Improving overall safety and security for customers and employees remains the top priority. The Company designs its distribution system to ensure safety is enhanced through rehabilitation and preventative maintenance of assets as well as using automation technology to spot issues before they occur. In particular, capital spending in the Rehabilitation sub-programs proactively replaces assets judged to be at risk of imminent failure by Company personnel. This vital work not only enhances the reliability of the system by addressing system deterioration, but also protects the public from assets at a higher probability of failure.

Q. Do any of the investments identified in the Reliability Roadmap primarily support safety goals?

A. Yes. The Reliability Roadmap identified voltage conversions, subsurface transformer replacements, open-wire secondary conversions, and key investments to improve public safety. Additionally, the Company's new effort to perform groundline inspections of LVD poles and replace any pole in poor asset health will improve both public and employee safety. Company witness Partlan discusses these investments in her direct testimony.

Q. Is the Company doing any other work that will enhance public and employee safety?

A. Yes. The Company plans to continue the O&M spending associated with its Wildfire Risk Mitigation Program, first introduced in Case No. U-21585. The Company also proposed capital investments for Wildfire Risk Mitigation in Case No. U-21585, but these were opposed by some parties, and the Commission did not approve the capital part of the

proposal. Per the Commission's directions in their final Order in Case No. U-21585, the Company has reassessed the costs and benefits of the program utilizing data specific to its distribution system and newly proposes capital investment for Wildfire Risk Mitigation in the instant case.

Q. What is the Company's Wildfire Risk Mitigation Program?

A. In the 2023 Reliability Roadmap, the Company analyzed multiple potentially emergent risks, such as wildfires and extreme precipitation, in its modeling.

As shown in Figure 18 below, these risks were originally deemed less immediate to Company assets compared to thunderstorms, high heat, and wind. However, multiple recent major wildfires in the United States, including wildfires triggered or exacerbated by utility infrastructure, illustrate the threat posed by wildfires. As a result, the Company has developed a program to mitigate wildfire risk. This plan is detailed in the Company's report *Mitigating Wildfire Risk in Consumers Energy's Service Territory*, which is included as Exhibit A-99 (EMD-15). In developing its plan, the Company researched other utilities' publicly available wildfire risk mitigation plans and held benchmarking discussions with several utilities, and concluded that there are four types of wildfire risk mitigation activities in use in the industry:

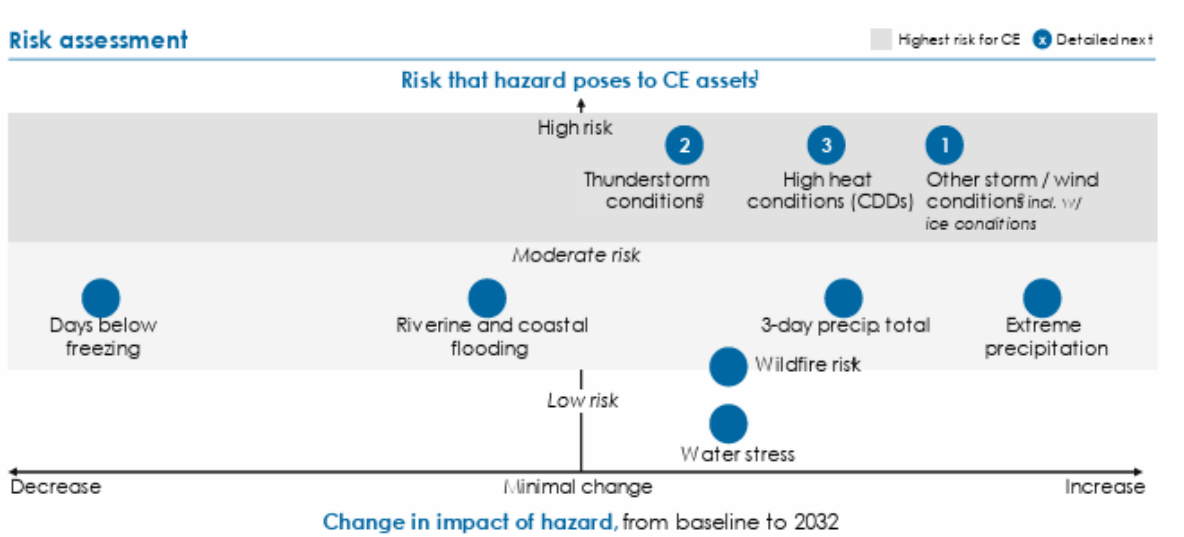
- **Situational Awareness:** Technology-based approaches that produce large amounts of data to inform decisions, including wildfire weather forecasting, enhanced inspections, sophisticated wildfire risk modeling, fire detection cameras, and fire spread modeling.

- **Operational Procedures:** Operating procedures designed to reduce ignition risk in wildfire-prone weather conditions, including modified field operating procedures, modified recloser settings, public safety power shutoff, and wildfire-specific emergency preparedness.

- **System Hardening:** Traditional investment in the system, including sectionalizing devices, installing covered conductor, undergrounding, and building microgrids.

- **Vegetation Management**: Increased frequency of line clearing, with expansion of scope to remove canopy on targeted three phase primary lines.

FIGURE 18
RELIABILITY ROADMAP CLIMATE RISKS EVALUATED



Q. How has the Company's wildfire risk assessment changed in the last year?

A. In Case Nos. U-21585 and U-21870, the Company utilized the Federal Emergency Management Agency ("FEMA") *National Risk Index* Wildfire Risk Index to quantify wildfire risk in Consumers Energy's service territory. In Case No. U-21585 the Commission ordered that "future recovery of capital expenditures in a new category such as this must be justified by quantifiable benefits and analyses and data specific to Consumers' own distribution system." Therefore, the Company worked with a third-party to conduct a wildfire risk assessment that leveraged Company-specific data and included a benefit-cost analysis for system hardening mitigations.

Q. Please explain the wildfire risk assessment conducted by a third party.

A. The wildfire risk assessment consists of:

- Ignition risk analysis;
- Impact analysis; and

- Benefit-cost analysis.

These analyses were performed at the zone level, which is defined as the portion of a circuit between protective devices. The methodology and results of the third-party wildfire risk assessment are described in detail in Confidential Exhibit A-102 (EMD-18).

Q. Please explain the third-party wildfire risk assessment ignition risk and impact analyses.

A. Ignition risk was calculated as the probability of failure times the conditional probability of ignition. A machine learning model was created to estimate the risk of outage failure based on numerous data sets including asset data, operational data, weather data, and vegetation data. To convert the failure probability estimated by the model into an ignition probability, a conditional probability driven by local data observations about historical outages and ignitions within the area of the zone was estimated.

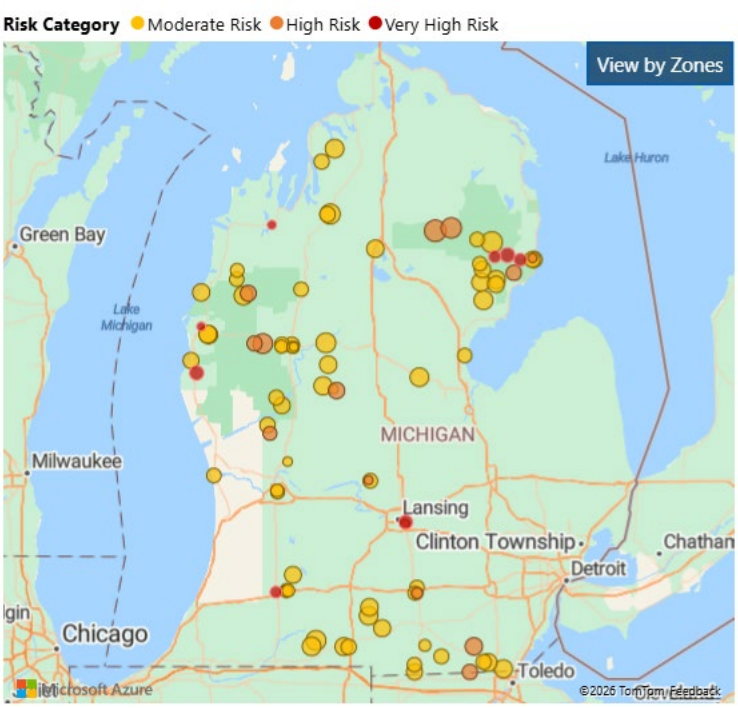
Impact was calculated as both total consequence and estimated annual loss ("EAL"), defined as total consequence multiplied by ignition risk. Impact calculations were based on the National Risk Index data available from FEMA which includes: (i) population consequence; (ii) building consequence; and (iii) agricultural consequence.

Q. What parts of the Company's system are at the highest risk from wildfires?

A. Areas of elevated wildfire risk within Consumers Energy's service territory based on the third-party wildfire risk assessment are shown in Figure 19 and classified as very high, high, and moderate.

FIGURE 19

IGNITION RISK IN CONSUMERS ENERGY'S SERVICE TERRITORY

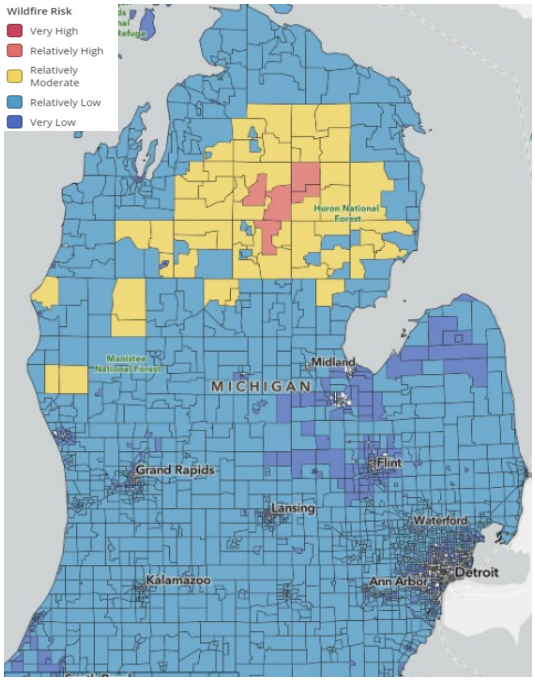


As a supplemental resource, the FEMA *National Risk Index* map of the United States that includes a Wildfire Risk Index score that was updated in December 2025 is shown in Figure 20 below. This map now indicates predominantly low to moderate wildfire risk across Consumers Energy's service territory. While FEMA mapping was previously used to inform wildfire risk and investment decisions, Consumers Energy now utilizes findings from the third-party wildfire risk assessment to inform and support the hardening investments outlined in my testimony.

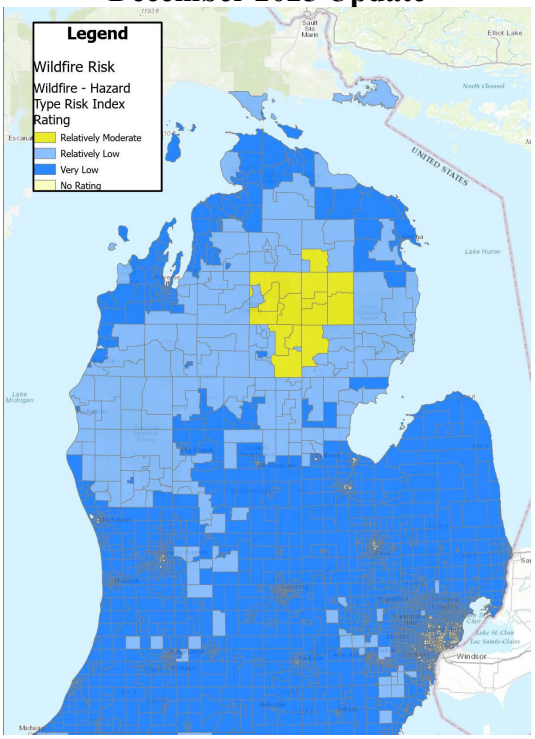
FIGURE 20

FEMA NATIONAL RISK INDEX – WILDFIRE HAZARD[10]

Prior to December 2025



December 2025 Update



Q. Please explain the third-party wildfire risk assessment benefit-cost analysis that was performed to substantiate capital investment in mitigating wildfire risk.

A. In order to perform this benefit-cost analysis, the Company worked with a third-party to calculate ignition risk and impact for Consumers Energy's service territory as described above.

Once the ignition risk and consequence baseline was established, the benefit-cost analysis was performed by considering the costs of mitigation options within a zone and comparing them to the expected reduction in EAL to derive a prioritization of mitigations by zone to maximize the reduction in wildfire risk.

[10] FEMA National Risk Index (https://hazards.fema.gov/nri/map)

Finally, to create a capital investment plan to mitigate wildfire risk, the Company focused on mitigating the high and very high ignition risk and impact zones, and developed a portfolio of mitigations that results in a benefit-cost ratio of 1.0. Based on this current analysis, this is the most prudent plan for the Company to put in place to mitigate as much wildfire risk as possible without cost exceeding benefit. The Company will continue to evaluate and update the five-year plan as new data and insights are available.

The benefit-cost analysis and related work performed by the third-party is described in detail in Confidential Exhibit A-102 (EMD-18).

Q. What work does the Company include in the Wildfire Risk Mitigation Program?

A. Wildfire Risk Mitigation activities, and the corresponding work for 2026 through 2030, are described in the Company's wildfire risk mitigation report in Exhibit A-99 (EMD-15).

As shown in Exhibit A-168 (JMP-2), page 14, lines 40 and 41, the Company is projecting $1,835,000 in capital investments in the test year in this case. This total amount is broken down as follows:

- $1,095,000 for covered conductor, and
- $740,000 for protective line devices.

Exhibit A-168 (JMP-2) lists the projects for these projected capital expenditures.

The Company is projecting $580,000 in O&M in the test year in this case. This total amount is broken down as follows:

- $70,000 for wildfire-specific weather forecasting; and
- $510,000 for Light Detection and Ranging ("LiDAR").

Q. What are the Company's plans for wildfire risk mitigation beyond the test year in the instant case?

A. The five-year plan presented in Exhibit A-99 (EMD-15) is the Company's effort to be transparent about future workplans and cost, as well as to follow industry best practices for publishing multi-year wildfire risk mitigation plans. However, the Company will continue to learn more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region. As it does so, it will continuously improve this plan by leveraging industry experts and peers, and learning about and deploying best practices.

The Company is including an updated five-year plan in Exhibit A-99 (EMD-15) to show the current vision and a more detailed benefit-cost analysis for its Wildfire Risk Mitigation Plan.

Q. Are there any other aspects of wildfire risk mitigation that you would like to discuss?

A. The Commission's Order in Case No. U-21585 instructed the Company to document coordination efforts with Department of Natural Resources ("DNR") and other agencies when requesting cost recovery for wildfire risk mitigation. The Company has engaged with agencies as follows:

- In November 2025, the Company met with the U.S. Forest Service ("USFS") and the Michigan DNR to conduct a downed wire awareness training session and to review the USFS incident command structure and coordinated response protocols.

- In April 2026, the Company participated in a wildfire preparedness meeting in Mio, MI with the USFS for the Huron Zone, which is identified as one of the most at-risk areas of the Company's electric grid. Participants included representatives from the U.S. Forest Service, Michigan DNR, local fire departments, the Michigan State Police, and the local Road Commission.

Feedback from these engagements indicated strong appreciation for the Company's proactive participation and focus on wildfire preparedness. These collaborative efforts strengthen interagency coordination and enhance wildfire response readiness across Michigan, supporting the effectiveness of the Company's wildfire risk mitigation plan.

Objective: Ensure system Reliability and Resiliency

Q. How do the Company's proposals in this case support the Company's objective to improve reliability and resiliency?

A. The Company continues to invest hundreds of millions of dollars in the distribution system to ensure its reliability and resiliency, repairing and replacing distribution assets, performing line clearing work, and investing in technology and automation projects to modernize the grid.

As already discussed above, the Reliability Roadmap, with its investments to reduce SAIDI and reduce asset health risk, is driving increases in investment in reliability and resiliency. In total, the Company is directing $668,725,000 of test year capital toward the Reliability Program.

LVD Reliability sub-programs are detailed in Company witness Partlan's testimony. Company witness Partlan also addresses the LVD Lines Capacity sub-program that also has reliability implications in the Reliability Roadmap. HVD Reliability sub-programs are detailed in Company witness LaFrance's testimony. Grid Automation investments are detailed in Company witness McPhail's testimony. Additionally, the O&M dollars spent on line clearing improves reliability by mitigating the risk posed by trees adjacent to distribution assets.

To further support the Company's efforts to invest in reliability and resiliency, the Company is proposing an updated IRM covering certain capital investments. The updated

IRM is discussed by Company witness Heidi J. Myers, and additional details are included later in my direct testimony.

Q. What external sources has the Company consulted for industry best practices for improving reliability and resiliency?

A. The Company has consulted, among other things, EPRI's *Distribution Grid Resiliency* reports published in 2015.

EPRI published a report on the prioritization of options for grid resiliency[11] incorporating research that EPRI conducted on overhead structures, vegetation management, undergrounding, grid technology, and storm response practices. This report provided a benchmarking analysis of the costs and benefits of various options for improving reliability and resiliency the Company can apply to its distribution planning, as well as discussion on how to rank the reliability of circuits so that projects can be prioritized.

While that EPRI report provides a foundation for the Company's distribution investment prioritization, the Company continues to stay active in various EPRI working groups, each of which allow Company personnel to stay up to date with best practices and potential breakthroughs at other utilities or from others doing research. Within the electric distribution space, these working groups include subject matter such as line design, substation operation and maintenance, distribution cybersecurity, and integration of DERs.

[11] *Distribution Grid Resiliency: Prioritization of Options.* EPRI, Palo Alto, CA: 2015. 3002006668.

Q. Which Company proposals in this case specifically support the resiliency of the system against increasingly severe weather?

A. The Resiliency sub-program found in Company witness Partlan's testimony includes two key efforts to support the resiliency of the system: Fractionalization and undergrounding. *Fractionalization* is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the impact of outages. *Undergrounding* completely replaces certain sections of overhead LVD lines with underground lines and associated equipment protecting distribution lines from weather and trees.

Q. How has the Company been treating undergrounding in rate cases?

A. In Case No. U-21389, the Company proposed an undergrounding pilot to allow the Company to explore how undergrounding can help improve reliability for customers, comparing the benefits and costs of this work. The Commission approved this proposal to cover approximately 10 miles of undergrounding, and the Company executed on this work in 2024 and early 2025.

As Company witness Michael P. Kelly discussed in Case No. U-21870, the pilot showed that underground projects can have a range of costs based on specific local conditions, but that overall costs average around $400,000 per line mile, and this represents a reasonable cost for assessing the costs and benefits of undergrounding in general. Based on that, the Company found that undergrounding compares favorably to overhead alternatives when evaluating them using a utility cost test or a societal cost test, with undergrounding either at parity with or superior to overhead alternatives in economic terms.

Based on that assessment of the pilot, in Case No. U-21870, the Company proposed 50 miles of undergrounding in the test year of that case. The Commission approved 11.3 miles, based on the argument that those were the highest-benefit miles of the 50 that were proposed, and stated that the Company would need to provide benefit cost analyses for each proposed undergrounding project in any future cases.

Q. What is the Company proposing regarding undergrounding in the instant case?

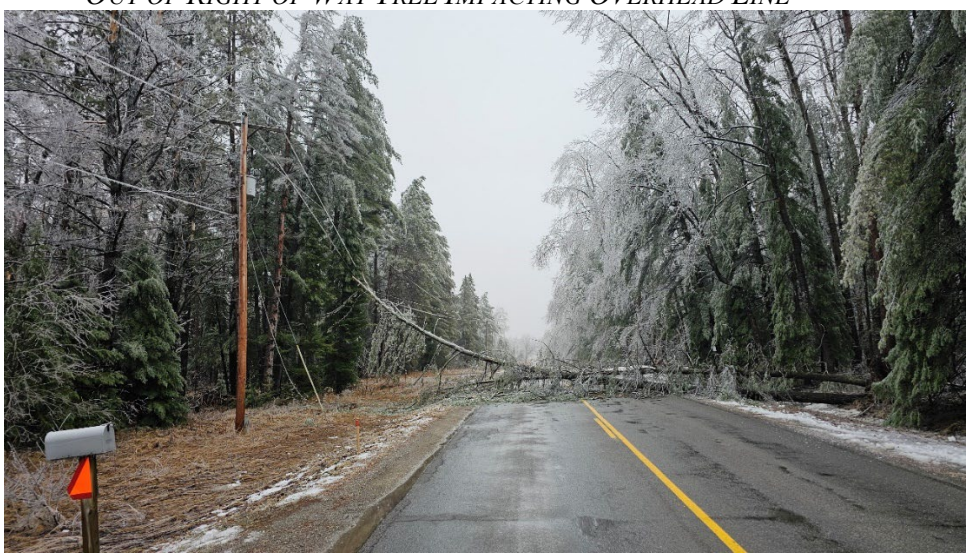
A. In the instant case, the Company is planning to complete the 11.3 miles of undergrounding work in the bridge period that the Commission approved in Case No. U-21870. In the test year, the Company is proposing to underground approximately 50 miles. This is essentially deferring the Company's proposed ramp-up in the Reliability Roadmap by one year to account for the reduction in Case No. U-21870. Company witness Partlan presents these proposed projects in her direct testimony and exhibits. As directed by the Commission, each test year underground project includes a benefit cost analysis, which Company witness Partlan discusses.

Q. What reliability benefit is undergrounding expected to provide?

A. Based on work conducted by peer utilities, most notably WEC Energy Group and Alliant, the Company would expect an improvement in reliability of 90% or more.

Any conductor that is not undergrounded, when in an area with trees, will always be exposed to trees and susceptible to outages during severe weather. As shown later in Figure 36, trees continue to drive a significant proportion of the Company's LVD SAIDI.

FIGURE 21
OUT OF RIGHT OF WAY TREE IMPACTING OVERHEAD LINE



Q. Why is it important for the Company to continue undergrounding conversions?

A. The Company is often compared to similarly situated utilities like those in Liberty's Report, Part I, Chapter VI, which have larger percentages of their distribution systems underground. Because of the size of the Company's distribution system, more miles need to be undergrounded to better align with the Company's peers, on a percentage of system undergrounded basis, and to provide customers with resiliency benefits comparable to these similarly situated utilities. On top of its sheer size, given the inclement nature of lake-effect weather, as noted by Liberty, the Company must invest in converting a minimum of 2,000 to 9,950 additional miles to compare to regional peers and to provide our customers with better reliability.

Objective: Clean and equitable grid

Q. How does the Company's distribution strategy support a clean and equitable grid?

A. The Company's distribution strategy is aligned with overall clean energy goals that involve increasing sustainability and reducing waste. The Company also continues to execute on

a detailed strategy to understand the distribution reliability experience of EJ communities, and to address inequity found to exist.

Increasing Sustainability and Reducing Waste

Q. How does the Company's distribution system support the Company's objective to increase sustainability and reduce waste?

A. In addition to providing Consumers Energy's customers reliable electric delivery service, the Company's distribution investments are also designed to help facilitate the transition to cleaner energy resources by integrating and optimizing DERs such as rooftop solar, as well as EVs, onto the system.

The Company's CVR investments reduce system losses, helping the Company meet load demand with less need for generation. The Company is considering sustainability through a broader scope by also including EJ factors in its distribution planning. This focus will address not only more equitable outcomes for customers, but also will lead to improved understanding of where the distribution system has sufficient hosting capacity to accept new distributed generation like solar.

Finally, the Company continues to ensure its investments are right-sized and appropriately targeted to avoid wasteful overbuilding of the system.

This can be seen, for example, in how the Company's Capacity Program investments are designed to address reasonably known and foreseeable load growth amounts without building more than is needed.

Q. How is the Company preparing to integrate and optimize DERs?

A. As technology matures and expands to more complex, larger, and widespread applications of DERs, incremental steps to gain expertise around DER deployment is the most sensible

approach. The Company is laying the groundwork for this through its DER Optimization initiative, detailed in Company witness McPhail's testimony. As this is rolled out in the coming years, it will allow the Company to manage and coordinate Company and third-party owned DER assets, applying best practices and lessons learned to deliver solutions best suited for Michigan and customers. The DER Optimization initiative is more important than ever, since the statutory distributed generation cap was increased from 1% of utility load to 10%. The Company will need DER Optimization to ensure it can manage that higher level of distributed generation on its grid.

Q. How is the Company planning for the rise in EVs on the distribution system?

A. As discussed in Company witness Alex M. Gast's direct testimony, the Company is working to optimize load from EVs in its service territory in support of the State of Michigan's policy goals. As noted in the Reliability Roadmap, the Company's current modeling indicates the highest levels of customer technology adoption, like EVs, will likely materialize on specific circuits, and while a limited number of circuits may start to approach their capacity thresholds by 2030, the Company's system is not likely to experience broader issues until closer to 2050.

Q. Is the Company doing any other work in the area of increasing sustainability or reducing waste?

A. As more customers adopt new technologies like DERs and EVs, hosting capacity will become a more prominent issue on the system, and hosting capacity analyses ("HCA") are important in addressing any concerns that arise. HCA is defined as "the amount of DERs that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without

requiring infrastructure upgrades."[12] DERs interconnect to the distribution system through a Commission-regulated process. HCAs can improve and streamline this process by identifying locations on the system with a high probability of accommodating DERs. While resource-specific analyses are still required with an HCA, an HCA can help customers and DER developers avoid proposing interconnections and incurring study costs in areas that are not suitable for DERs.

Q. What is the Company's recent history with HCAs?

A. In 2020, the MPSC directed the Company to pursue a "phased" approach to developing HCAs, with two primary phases:

- Phase I: A base-level approach with a zonal go/no-go map; and
- Phase II: Specific, detailed analyses on areas of the distribution system with high DER penetration, incorporating this information into a more detailed map with circuit voltage-level information as DER penetration continues to increase.

The Company completed a Phase I analysis and reported the initial results in its 2021 EDIIP filing, with a detailed description of Phase I methodology. Additional updates were made to this Phase I analysis in subsequent years as the Company worked towards developing its Phase II analysis.

Q. What progress has the Company made in Phase II analysis?

A. In its July 10, 2025 Order in Case No. U-20147, the Commission directed the Company to publish a Phase II HCA map on its website by October 1, 2025, and to update the map at least quarterly. The Company published its map by that deadline at the following URL: https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d

[12] MPSC Case No. U-20147, August 20, 2020 Order.

Since the initial publication, the Company has generally been updating the map on a monthly basis.

Addressing Distribution Equity

Q. How has the Company considered EJ factors in its distribution planning?

A. In the Settlement Agreement in Case No. U-21224, the Company agreed with the other parties that in future versions of the EDIIP and/or future rate cases, the Company would study reliability performance and hosting capacity on circuits that overlap with EJ communities. Since the end of 2022, the Company has engaged in ongoing, increasingly detailed, analysis of distribution system performance in EJ communities, which were defined as "census tracts that are above the 80th percentile on the MiEJScreen Overall Score." Company witness Kelly presented details of these analyses in testimony in Case Nos. U-21389, U-21585, and U-21870. Those analyses have built on one another, and each remains valid even as the Company has deepened its understanding. To date, all analyses have indicated that (a) on a systemwide basis, the Company's EJ communities have comparatively good reliability, but (b) there are particular EJ communities that do face reliability challenges, and given their socioeconomic vulnerabilities the Company has outlined specific new investments to those communities to improve their reliability, which are part of the Vulnerable Communities Resiliency Plan ("VCRP").

Q. What is the VCRP?

A. The VCRP makes targeted strategic investments on EJ circuits with a goal of ensuring that every EJ circuit in the Company's service territory has SAIDI, including MEDs, that is in the second IEEE quartile or better. In other words, the VCRP will ensure that no EJ circuits experience worse than industry average reliability, and it will do so including MEDs to

account for the actual experience of those customers. The VCRP targets EJ circuits, not EJ census tracts, because electrical geography (represented by circuits) does not always align with political geography (represented by census tracts). Circuits do not neatly follow census tract boundaries, and since investments are based on circuits (or zonal subsets of circuits), the Company cannot directly invest in "census tract reliability." Since every circuit serving an EJ census tract is an EJ circuit, investing in EJ circuits ensures the Company invests in every EJ census tract.

Q. What investments are included in the VCRP?

A. Over a period of several years, the VCRP includes incremental investments that align with investment types that already take place in the Company's Reliability capital program, particularly in LVD Lines Reliability and Resiliency. Planned investments include fractionalization, including new substations and new circuit exits in existing substations; rebuilds of primary LVD circuits to create a high-reliability mainline three-phase; and other miscellaneous work such as new reclosers and switches. With the exception of new substations, this work is all intended to be incremental above the investments outlined in the 2023 Reliability Roadmap.

In its final Order in Case No. U-21870, the Commission stated that, in the instant case, it "expects to see how the initial $30 million was used to improve the reliability of LVD service in the targeted communities and the element of additionality that will demonstrate this, along with how the VCRP fits into the Company's broader approach to distribution improvements."

Q. How do you address that Order language?

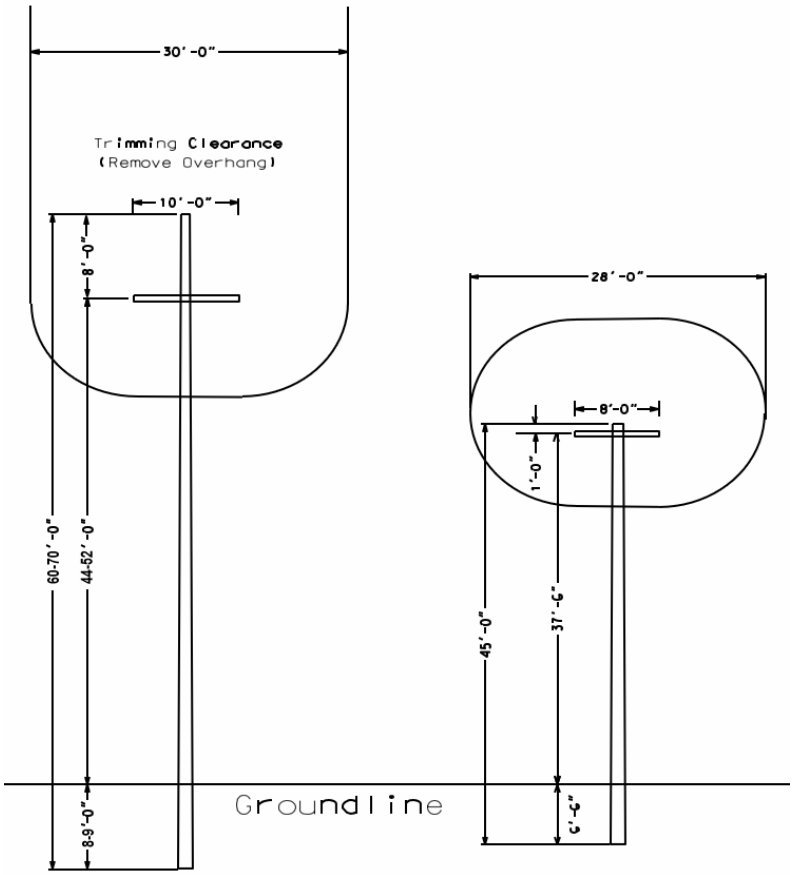
A. Regarding the first point, the initial VCRP investments proposed and approved in Case No. U-21870 applied to the test year in that case, which only began on May 1, 2026. Correspondingly, it is still too early to assess, in the past tense, how those initial investments were used to improve reliability, nor can the Company yet assess actual results of the investments. However, the Company can demonstrate that the VCRP investment from both Case No. U-21870 and the instant case are "additional" to investments proposed in the 2023 Reliability Roadmap. Specifically, all VCRP investments in both cases serve to upgrade the targeted LVD lines to a new higher-standard "mainline" design that will be more resilient to interruptions.

This "mainline" concept had not been developed when the 2023 Reliability Roadmap was published; thus, these VCRP investments were not in the 2023 Reliability Roadmap. While this mainline concept is, at this point, being solely deployed for VCRP work, the Company may implement it on other parts of the LVD system in the future.

Q. Describe how "mainline" construction compares to standard construction.

A. "Mainline" construction incorporates aspects of HVD construction to strengthen the LVD system. It utilizes taller poles, shielded wire, larger trimming clearance, and overhead removal. While standard LVD construction generally results in one fault per four miles, HVD construction generally results in one fault per fifty miles. "Mainline" construction would reduce the number of faults per mile compared to standard LVD construction. See Figure 22 for how "mainline" construction compares to LVD standard construction.

Figure 22

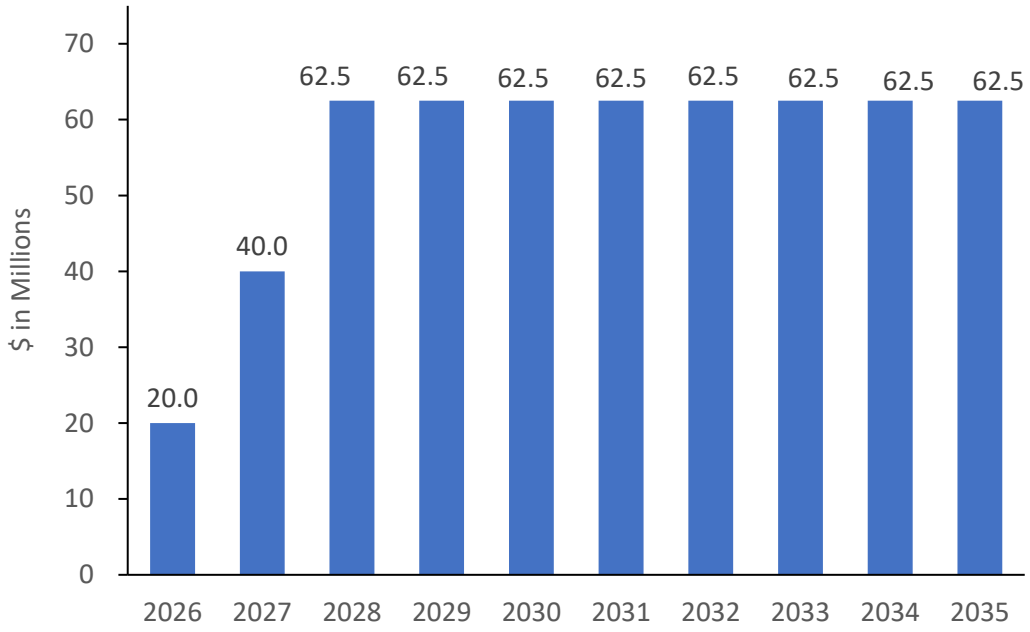


Q. What specific investments in the VCRP are included in the instant case?

A. Proposed test year projects for the VCRP are included in Company witness Partlan's project list exhibit, and can be found in Exhibit A-168 (JMP-2), page 14. These investments represent a total of $40,000,000 in the test year, building on the $30,000,000 in the bridge period that was already approved in Case No. U-21870.

When the Company first introduced the VCRP in Case No. U-21585, it estimated that the necessary investments would total approximately $600 million over ten years. The Company expects that the exact investment amounts in future years will vary as projects are identified and designed, but the estimated ten-year glidepath is as follows:

FIGURE 23
VCRP TEN-YEAR GLIDEPATH



Q. How has the Company analyzed the reliability experience of EJ communities?

A. The Company has conducted several analyses of EJ reliability, which were presented and discussed in detail in Case Nos. U-21389, U-21585, and U-21870. In its order in Case No. U-21389, the Commission directed the Company to also conduct a regression analysis related to EJ reliability. The Company spent considerable time in 2024 studying this issue, including dialogue with MPSC Staff and other intervenors, and presented the regression analysis in Case No. U-21870. In accordance with the final Order in Case No. U-21585, this analysis included information about residential shutoffs.

Q. What did that analysis, as presented in Case No. U-21870, show?

A. The Company's assessment included a large number of different types of statistical analyses, including different types of regression analyses, to evaluate questions of differing reliability performance and differing experiences with involuntary shutoffs across areas of differing socioeconomic status and other conditions. A large number of individual analyses

yielded statistically insignificant results, making it difficult to discuss all of the results in a fully comprehensive manner.[13]

The analyses did indicate that, when statistically significant differences exist, it is consistently the EJ, urban, low-income, and high-percent-minority tracts that have better reliability. This was congruent with the Company's own analysis as presented in Cases Nos. U-21389 and U-21585. The Company also studied census tract-level reliability. Where statistically significant correlations existed, these analyses showed that higher MiEJScreen scores are correlated with improving reliability. However, these analyses also showed instances where increasing poverty levels and increasing unemployment rates are correlated with worsening reliability, in terms of SAIDI and SAIFI as well as outage duration. These analyses also found no significant correlation between reliability and whether a circuit serves urban, low-income, or high-percent-minority census tracts. However, they did find instances where circuits serving EJ census tracts are more likely to experience customer interruptions, as measured by SAIFI excluding MEDs.

Q. Did the Company incorporate the results of the regression analysis, as presented in Case No. U-21870, into its distribution investment plan?

A. Yes. As discussed by Company witness Kelly in that case, a large number of individual analyses returned no statistically significant results. Still, the regression analyses of census tract-level and circuit-level reliability did indicate some ways to interpret data that indicate that there are certain areas within EJ communities that do face worse reliability. These observations underpinned the need to make targeted investments in the VCRP in those EJ

[13] Refer to Exhibit A-135 (MPK-25) in Case No. U-21870.

communities that do have poor reliability, given their particular vulnerability to frequent and/or extended outages.

Q. Has the Company conducted further regression analyses in the instant case?

A. Yes. The Commission's Order in Case No. U-21389 indicated that regression analyses should be included as a regular matter in rate cases going forward, at least until otherwise directed. The Commission's Order in Case No. U-21870 confirmed this, and provided some minor refinements on variables to be included based on intervenor testimony. Accordingly, the Company has conducted another analysis for the instant case, and it is included as Exhibit A-97 (EMD-13). The Company is providing the parties the underlying data for the analysis in Exhibit A-97 (EMD-13) as workpaper WP-EMD-7.

Q. What are the findings of the regression analysis in Exhibit A-97 (EMD-13)?

A. Please note that a comprehensive summary of the analysis is provided as Exhibit A-98 (EMD-14).

The analysis in Exhibit A-97 (EMD-13) effectively represents an update to the analysis presented in Case No. U-21870, accounting now for actual reliability data from 2025. Because of this, the analysis in Exhibit A-97 (EMD-13) yielded very similar results to the analysis presented in Case No. U-21870.

As in Case No. U-21870, Exhibit A-97 (EMD-13) includes multiple analyses comparing average reliability of different types of census tracts, comparing EJ vs. non-EJ tracts; urban and rural tracts; low-income and high-income tracts; and high-percent-minority vs. low-percent-minority tracts. These analyses indicated, as they did in Case No. U-21870, that when statistically significant differences occur, it is consistently the EJ

census tracts, the urban census tracts, the low-income census tracts, and the high-percent-minority census tracts that experience better reliability.

The analysis in Exhibit A-97 (EMD-13) also repeated the mixed-effects linear regression evaluating the demographic characteristics of census tracts and reliability. This found that SAIDI improves as a census tract's MiEJScreen Tool score increases and as population density increases, but gets worse as unemployment percentage increases; for each of these variables, the rate of impact was very close to what was observed in Case No. U-21870. Poverty levels and housing burdens had been statistically significant variables in Case No. U-21870, but no longer are. An appreciable number of analyses for metrics other than SAIDI found no statistically significant correlations.

The analysis in Exhibit A-97 (EMD-13) also included a mixed-effects linear regression related to circuit (or "feeder," in the text of the analysis) characteristics. In Case No. U-21870, this analysis had found a few instances in which the demographic characteristics of a circuit were correlated with the circuit's reliability, but the analysis in Exhibit A-97 (EMD-13) finds no correlation between any demographic characteristics and reliability. Some physical construction circuit characteristics have statistically significant correlations with reliability, in a similar fashion to what was found in Case No. U-21870.

Finally, the analysis in Exhibit A-97 (EMD-13) studied correlations between demographic characteristics and disconnection rates. Unlike in Case No. U-21870, this analysis considered energy burden as an additional potential explanatory variable, and this analysis found that energy burden is a much more significant predictor of disconnection rates than other variables. The analysis of disconnection rates is further discussed by Company witness Gast.

Q. What conclusions do you draw from the regression analysis in Exhibit A-97 (EMD-13) regarding equity of reliability?

A. As in Case No. U-21870, a large number of individual analyses performed in this exercise returned no statistically significant results. The results discussed above represent those fairly few instances where clear results could be identified. The first set of analyses mentioned above – evaluating whether one set of census tracts or the other have better reliability – continue to confirm the Company's ongoing analyses dating to Case No. U-21389, that there is nothing apparently systemic or unique about EJ census tracts (or other potential groupings of disadvantaged census tracts) as a whole that give them worse reliability. The regression analyses of census tract-level reliability continue to show certain, relatively isolated, instances where disadvantaged communities face worse reliability, which the Company believes continues to support the need for the VCRP, which has a stated goal of making sure that *no* EJ communities have poor reliability.

Given that: a) many individual analyses continue to not return statistically significant results; b) statistically significant results that do exist usually point to better reliability in vulnerable communities; and c) the analysis presented in Exhibit A-97 (EMD-13) largely confirms the results presented in Case No. U-21870, I recommend that the Commission remove the requirement to reconduct this analysis in subsequent rate cases. If the Commission believes such an analysis continues to have merit, the requirement could be moved to the five-year Distribution System Plan, to be updated every three years. Although this analysis has produced useful insights, given the repeated results, it is not necessary to incur the time and expense to continue to run the analysis on an annual basis.

Q. Has the Company produced any maps to graphically represent reliability in EJ communities?

A. The Commission's Order in Case No. U-21389 directed the Company to work with Staff to develop a means for interested parties to access Geographic Information System ("GIS") data from the Company, and the Company undertook this effort during late 2024 and early 2025. This process resulted in two new public outputs. First, the Company posted interactive GIS maps to its public website that show EJ circuits overlaid with EJ census tracts in the Company's service territory, showing SAIDI and SAIFI by circuit, with and without MEDs. These maps can be accessed at: https://experience.arcgis.com/experience/1d84e089ff5e4a2382df340d15689488. Second, the Company created an online form on its public website that allows interested parties to access GIS data. This form can be accessed at: https://www.consumersenergy.com/about-us/electric-generation.

In its final Order in Case No. U-21870, the Commission directed the Company to make continuous improvements to the user-friendliness of its GIS map, including a clear key explaining acronyms and data categories, and intuitive and navigable map controls. The Company has made these requested improvements.

Q. Has the Company performed any hosting capacity analyses related to EJ communities?

A. Yes. This was another stipulation agreed to in the Settlement Agreement in Case No. U-21224, and the Company provided Phase I hosting capacity analysis maps for EJ communities as exhibits in Case Nos. U-21389, U-21585, and U-21870. Since the Company has now published its more detailed Phase II hosting capacity analysis online

with regular updates, as discussed above, those online maps can be used to review the current hosting capacity in any EJ area.

Objective: Provide competitive, affordable rates

Q. What avenues is the Company pursuing in its distribution strategy to deliver competitive, affordable rates for customers?

A. As already discussed, the Company is committed to delivering reliable power to its customers, and doing so requires significant investment and maintenance in the system to meet the challenges to the grid outlined in the Reliability Roadmap. As the Company invests in meeting these challenges, it is committed to optimizing its work so that dollars are responsibly spent and impacts to rates are mitigated. I have already discussed how slower SAIDI improvement glidepaths would have a negligible impact on customer rates over the next several years, and in one scenario it would actually result in higher rates for customers over the remainder of this decade, due to higher restoration costs. This illustrates how the Company's long-term distribution investment strategy is reasonably balanced between improving reliability and affordability. In the next section of my direct testimony, I will address the ways that the Company ensures that it chooses the optimal project for given situations, typically looking for the least-cost option that will address the identified problem.

Q. Is the Company pursuing any outside funding for distribution investment to help offset rates?

A. At present, the Company is not pursuing any outside funding specific to distribution. However, the Company will identify and pursue appropriate grants as they become available. The Company will also continue to work with university partners to take

advantage of their expertise in avenues for improving reliability. For example, Company witness Dickey describes the Outage Prediction Model that the Company is collaborating on with two universities.

Q. Are there any specific practices that the Company uses to improve efficiency in distribution work?

A. The Company pursues opportunities to coordinate with external parties to lower project costs, particularly for larger projects. For example, for many Metro and HVD projects, the Company holds planning meetings with municipal engineers to assess how the Company's work can be coordinated with planned local government infrastructure projects. As an illustration, the Company engaged in a "coordination of utilities" project in recent years with the City of Flint to rebuild Metro facilities while the city was replacing water mains and rehabilitating streets, sidewalks, and traffic signals. This kind of coordination reduces project costs by employing a "dig once" strategy. The Company also routinely coordinates HVD projects with work being undertaken by METC, the transmission owner.

IV. CAPITAL SPENDING OVERVIEW

Q. How does the Company ensure that its electric distribution capital planning process selects the correct alternatives?

A. The Company is committed to making investments in its distribution system to ensure they will deliver clear and cost-effective customer benefits and not just making investments for their own sake. For traditional investments on the distribution system, the Company generally uses a least-cost, best-fit ("LCBF") analysis to identify the optimal project. When an asset has failed or is in poor health and at risk of failing, or if it is projected to be overloaded soon, or must be relocated, the Company has no alternative but to address the issue to ensure customers continue receiving reliable service. The Company identifies the

least costly solution that will satisfactorily solve the issue. The Company has used more extensive benefit-cost analyses for some non-traditional investments.

Q. What do you mean by "traditional" and "non-traditional" investments?

A. In the context being used here, the Company defines "traditional" distribution investments as investments in components of lines (such as poles, pole tops, conductor, and certain devices), substation infrastructure, and other related items, across a variety of investment programs. Conversely, the Company defines "non-traditional" distribution investments as those in newer technologies, such as those covered in Grid Automation, or in certain pilot programs.

Q. Can you provide more detail regarding how LCBF analysis works?

A. Yes. The overarching principle of LCBF is that once the Company has identified an issue on the distribution system that must be addressed, the Company identifies and chooses a solution that satisfactorily fixes the issue for the least cost.

The identified issue may be a failed piece of equipment, a circuit or subset of a circuit with persistently poor reliability, an overloaded piece of equipment, an asset that must be relocated, or any number of other issues. LCBF analyses ensure investments are both cost-effective and meet the necessary functionality and capability requirements.

LCBF analyses themselves are not necessarily used to rank and prioritize projects against one another. As discussed elsewhere in testimony, particularly by Company witnesses Partlan and LaFrance, the Company prioritizes the assets that need to be addressed based on a variety of inputs, depending on the specific investment program. Once assets have been prioritized and the Company has determined where work is needed, LCBF is used to select the type of project to execute in that location.

LCBF is commonly recognized in the utility industry as an appropriate means for evaluating traditional reliability investments. It is important to note that LCBF does not always lead to the Company selecting the lowest cost alternative outright, because the "best fit" part of the principle must also be considered.

Q. In identifying a solution, how does the Company compare different potential projects with one another?

A. For some smaller projects, the Company may identify a solution based on what has been known to work in similar circumstances in the past, applying the LCBF principles discussed above. For many larger projects, the Company uses a more formal process to compare proposed electric distribution investment against alternatives, developing a "concept approval" to test and demonstrate why the selected project is reasonable and prudent, ensuring strong and robust justification for selected electric distribution projects.

For example, concept approvals for the Company's top 25 distribution projects are provided to the parties with Part III Requirement 142 in this case. The general structure of a concept approval includes the following:

1. Identification of the problem;
2. Identification of alternatives to address the problem;
3. Determination of costs and benefits of the alternatives;
4. Selection of best alternative;
5. Approvals; and
6. Revisions, if necessary (i.e., if costs and/or project scope change substantially following approval).

Q. Please explain the Company's process for concept approvals.

A. The process begins by the Company's planning engineers identifying problems (such as by reviewing reliability data and projected overloads) and system needs (such as by reviewing customer or third-party requests).

Once the problems or needs are identified, the planning engineers develop a list of alternative solutions. For each alternative, costs, benefits, and intangible considerations are developed. Although the planning engineer is responsible for this process, there is significant collaboration with design engineering, construction, and operating personnel in each phase of the process.

The alternatives are then compared against each other, and the planning engineers identify a selected alternative. The Company identifies selected alternatives using an LCBF, as discussed above. In other words, investment that yields the best fit is intended to produce the maximum benefit at the least cost. This ensures the Company's investment is optimized for customer benefit.

The final step of the process is to document all the information in a concept approval document that is routed through management for approval. In most cases, concept approval documents go to a program manager for review and approval, but could require additional approvals, depending on the projected cost of the project.

Q. Please provide an illustrative example of the concept approval process.

A. Au Gres Township passed a medical marijuana ordinance resulting in five customers requesting electric service for marijuana grow facilities totaling 2.8 megavolt amperes ("MVA"). The electric system in that area could not support an incremental 2.8 MVA of demand.

In response to these requests, the Company's planning engineers reviewed the surrounding electric system to determine conceptual alternatives for serving the incremental demand. The concept approval document included four alternatives involving different locations for substations connected at different voltage levels.

For each alternative, the Company developed a projected cost, feasibility, and timeline based on performing similar work in the past. In addition to the costs, the Company's planning engineers examined other considerations for each alternative, including availability of ROW, reliability impact, and ability to meet timeframes requested by the customers.

A selected alternative was identified as the best fit project to provide reliable service to the Au Gres area. The problem statement, alternatives, and selected alternative were documented in the Company's concept approval form and routed to management for review and approval. Once approved, the selected alternative was commissioned for ROW acquisition, substation and line design, and construction.

ROW challenges and new customer load requests totaling 6.8 MVA necessitated a revision to the selected alternative as it was apparent the originally selected alternative was no longer viable at the approved cost. Additionally, easements for a new 138 kV line were unable to be obtained along the proposed route, and it was determined a significant number of wetlands were present in the area. Lines passing through wetlands require a lengthy permitting process and often costly mitigation work. A revised concept approval with this new information and costs was needed.

The revised concept approval document showed the changes from the original document to concisely convey them to management. These changes included updating the

problem statement, including new or revised alternatives, and refining the costs and benefits. The revised concept approval followed the same process as the original, with the Company's planning engineers developing alternatives, costs, and benefits, and then seeking management approval of the selected alternative.

The newly included fifth alternative for the Au Gres area was the selected alternative because it was a solution to both serve the new incremental customer demand and improve reliability to the area.

The revised concept approval and selected alternative did not pass through the approval process without questions. Discussions between management and planning engineers led to the identification of improvements within the selected alternative. Specifically, the circuit configuration was refined to further improve reliability to the area customers. These circuit configuration improvements were included in the concept approval for documentation purposes, but the selected alternative did not change.

The revised concept approval was ultimately approved, and the newly selected alternative was commissioned for ROW, design, and construction.

Q. How do customers benefit from the concept approval process?

A. The concept approval process provides a rigorous approach and governance structure to identifying problems and needs, alternative solutions, and recommended alternatives. It provides for peer review and management oversight to ensure the Company's investment plans are well justified, reasonable, and prudent for customers.

Q. How does the Company classify its distribution capital investments?

A. The Company makes capital investments under two broad classifications, *unplanned* and *planned*, as outlined in Figure 24 below.

FIGURE 24
PLANNED AND UNPLANNED DESCRIPTIONS

Classification	Description	Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades, and investments in new tools and technology.	Reliability, Capacity, Electric Other, Wildfire Risk Mitigation
Unplanned	Demand-driven, customer-driven, or other reactive needs.	New Business, Demand Failures, Asset Relocations

Each of these classifications correspond to one or more capital "Programs," and they are:

- Reliability;
- Capacity;
- New Business;
- Demand Failures;
- Asset Relocations;
- Electric Other;
- Vulnerable Communities Resiliency Plan; and
- Wildfire Risk Mitigation.

Each Program is in turn divided into several "sub-programs," and many sub-programs are divided into several "investment categories."

Programs can include spending on LVD, HVD, and Metro assets, but each sub-program and investment category is specific to a single asset classification. Company witnesses Partlan, McPhail, and LaFrance each explain how investments are broken into sub-programs and investment categories under the seven overall programs identified here.

Q. What work is completed in the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, particularly by reducing system outages and hardening

the system. This includes installing, upgrading, and rehabilitating LVD and HVD lines, LVD and HVD substations, Metro underground assets, and protective relay systems; it also includes investments to modernize the grid through Grid Automation.

Reliability Program investments are a major contributor to the Company's efforts to address deterioration. While other programs may replace deteriorated assets as a secondary consideration, many Reliability investments have the express purpose of doing so. Grid Automation investments are included in the Reliability Program because many of the automation capabilities delivered by Grid Automation improve reliability for customers. As discussed above, the Company is planning an increase in investment in the Reliability Program under the plan outlined in the Reliability Roadmap.

Q. What work is completed in the Capacity Program?

A. The Capacity Program is designed to:

1. Ensure that the HVD system can serve forecasted peak demand when all HVD facilities are in service;
2. Ensure that individual HVD facilities can be taken out of service during non-peak period without loading equipment beyond ratings or providing unacceptably low voltage;
3. Address LVD equipment overloads that have occurred; and
4. Proactively address LVD equipment that has run at a higher loading than rated for.

Additionally, the Capacity Program includes the CVR sub-program that puts that component of the Company's IRP into effect.

Q. What work is completed in the New Business Program?

A. The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. This includes the costs of installing poles, conductor, transformers, meters, and in some cases, entire new

substations. Because of the Company's obligation to serve customers, the Company generally is required to provide the requested interconnections if the customer meets the requirements set by the Company's tariffs.

Q. What work is completed in the Demand Failures Program?

A. The Demand Failures Program addresses issues related to customer interruptions or failures of equipment on the system. When equipment fails and customers are interrupted, the Company is obligated to fix the issue and restore customers as quickly as possible. The program also enables the Company to respond to day-to-day equipment failures, even if customers may not be interrupted. If the Company fixes failed equipment in this process, the capital expenditures take place in the Demand Failures Program.

Q. What work is completed in the Asset Relocations Program?

A. The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, including those requested by municipal governments, as well as internal Company projects.

Q. What work is completed in the Electric Other Program?

A. The Electric Other Program consists of additional capital investment to support the distribution system that does not fall into one of the other five programs.

Q. What work is completed in the Vulnerable Community Program?

A. This line item in my exhibits represents the work being done in the VCRP that I described earlier in my direct testimony.

Q. What work is completed in the Wildfire Risk Mitigation Program?

A. The Wildfire Risk Mitigation Program is aligned with the Company's wildfire risk mitigation strategy that I described earlier in my direct testimony.

Q. Referring back to Figure 24, please describe unplanned investments.

A. Several of the Company's capital investment programs respond to demand-driven, customer-driven, or other emergent needs. These investments are not strictly "unplanned," as the Company does anticipate it will have to make these investments to replace failed equipment, and to add new customer connections to the system. However, due to the emergent nature of these needs, the Company's investments can be difficult to plan with specificity in advance, because it is not possible to know the exact number of equipment failures that will occur or new customer connection requests that will occur, or where such needs will occur. Instead, the Company forecasts the number of new business services that will be requested in the future based on historical service levels and projected growth rates, as further discussed in Ms. Partlan's direct testimony. The Company then applies a unit cost to these expected requests to develop a forecasted level of spending. These unplanned programs consist of New Business, Demand Failures, and Asset Relocations.

Q. Please describe planned investments.

A. In addition to the investments addressing emergent needs described above, the Company also plans investments further in advance to proactively improve the grid through reliability improvement projects, capacity upgrades, and investments in new tools and technology. These programs consist of Reliability, Capacity, Electric Other, and Technology.

Q. Are all investments in the planned programs identified and planned equally far in advance?

A. No. Individual projects vary widely in size, scope, cost, complexity, and other factors, and they correspondingly vary in how far in advance they are planned. For example, on the HVD system, substation and line rebuilds are large, complex projects with long lead times

for design and construction work, so those projects are planned more than a year in advance. Conversely, individual pole replacements on the HVD system are comparatively simple, with lead times in the order of weeks, so the Company does not identify individual poles for replacement months or years in advance; instead, the Company identifies HVD lines on which it will inspect poles in advance, with an expectation that, based on historical inspection experience, a given number of poles inspected will require replacement.

Q. Did the Company spend less in any of the aforementioned Programs compared with the amounts approved?

A. Yes. The Company spent less in the Electric Other Program by approximately $2.0 million. This capital was spent for truck tool kits as part of fleet expenditures to ensure Company vehicles are properly equipped for safe and effective operations.

Q. Where was this amount actually spent?

A. In total, the Company spent more capital than approved in Case No. U-21585 in Electric Distribution. Expenditures in the New Business, Reliability, Capacity, Asset Relocations, and Demand Failures Programs maintained the Company's commitment to delivering safe and reliable service to customers. The reduced spending in the Electric Other Program was allocated to these Programs.

Q. What capital projects does the Company expect to invest in during the bridge period and the test year?

A. Specific distribution projects for the bridge period and test year are discussed by Company witnesses Partlan, LaFrance, and McPhail, and are identified in their exhibits.

Q. What information is included in these exhibits?

A. The exhibits include projects identified with scope, cost, location, benefit type, and benefits. Figure 25 below identifies quantifiable benefit types.

FIGURE 25
INVESTMENT BENEFIT DESCRIPTIONS

Benefit Type	How Benefits were Quantified
Customer-outage-minutes	Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.
Customers Impacted	Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."
NOTE: Not all projects have quantifiable benefits. Some projects in the Capacity, Reliability, and Electric Other programs are completed for regulatory compliance, operating efficiency, or based on the Company's obligation to serve.	

Q. What is meant by a "Customer-Outage-Minute" benefit?

A. *Customer-outage-minutes* (sometimes referred to as customer minutes interrupted or "CMI") is a mathematical product of the number of customers that experience an extended outage of electrical service, and the duration in minutes of that outage. These numbers are gathered through the Company's outage management systems for each outage. For example, a failure on the LVD system that interrupts electrical service to 100 customers for 170 minutes would accrue 17,000 customer-outage-minutes.

A reliability project will reduce this number by reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. The planning engineer will determine the amount of savings based on both the historical outage data of that part of the system and the expected effectiveness of the solution selected. For example, if the historic average customer-outage-minutes of an LVD zone were 20,000 per year and the proposed project

would reduce the probability of that outage by 70%, the customer-outage-minutes saved or avoided by completing the work would be 14,000 (70% of 20,000). In this way, the benefit of a distribution reliability project can be quantified.

Q. How do the Company's projected customer-outage-minutes in the instant case compare to the Company's SAIDI levels or projections about SAIDI in the future?

A. While there may be an indirect connection between customer-outage-minutes avoided and SAIDI, they are two separate things and should not be conflated. Customer-outage-minutes avoided is a way to model the future outages that *would likely* occur on a circuit, line, or substation if a project is not done and the asset were to fail. For some assets, especially substations, historical outages are generally infrequent, meaning their historical contribution to SAIDI is relatively low, and projects will not necessarily significantly decrease SAIDI in the future. However, substation failures are high-impact events when they do happen, so a substation project may have a high number of customer-outage-minutes avoided, because the project prevents a future failure and therefore prevents many future outages that would have otherwise happened.

In general, for any type of asset, investments to reduce the likelihood of future outages do have a large impact on the projected number of future customer interruptions that would happen absent the investments. For example, if the Company assesses that a transformer is at risk of failure, and failure would cause 10,000 customers to lose power for 24 hours, the Company will conclude that replacing the transformer avoids those outages in the future, which is a reasonable assessment even if there have not yet been actual historical outages to consider. By considering projected customer-outage-minutes

avoided in this manner, the Company can meaningfully compare the relative benefits of different potential projects.

Q. What is meant by a "Customers Impacted" benefit?

A. *Customers impacted* is the number of customers who are served by an asset or project and therefore would experience an outage of electrical service if this asset were to fail or would realize a benefit to reliability with its improvement.

Q. Is the Company's test year capital plan executable at the proposed level of spend?

A. Yes. Consumers Energy's capital plan is executable at the proposed level: 2025 electric distribution spend was $1.28 billion, and the $1.46 billion test year reflects a manageable 14% increase. The proposal is also below the $1.53 billion requested in Case No. U-21870 and about 18% lower than the amount in the 2025 Reliability Roadmap. Additionally, the plan is supported by a balanced headcount, with LVD and HVD resource needs for 2026 through 2028 lower than those in the 2025 Reliability Roadmap.

Q. Does the Company propose to receive deferred accounting authorization in this case for the New Business, Demand Failures, and Asset Relocation programs?

A. Yes. While the Company attempts to project investment needs for the New Business, Demand Failures, and Asset Relocations programs, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests that it be allowed to continue to defer the revenue requirement for any capital spending for these programs above what is included in rates, if the spending exceeds what the Commission approves in this case. The Company agrees to the same stipulations the Commission approved for deferred accounting treatment for these programs in Case No. U-21585 and continued in Case No. U-21870. One of the stipulations is that the Company

spend the amount approved by the Commission in the Line Clearing Program. The Company requests a continuation of the treatment approved in Case No. U-21870 that the threshold for the aforementioned stipulation be set at the O&M "baseline" expense as proposed by Company witness Stewart. As further described in the direct testimony of Company witness Stewart, the total Line Clearing Program expenses are bifurcated between "total" and "baseline" O&M expenses required for ramping up line clearing to achieve a five-year cycle on the LVD system. Continuing this treatment, the defined "baseline" O&M serves as a floor to ensure that the Company does not receive the deferred accounting discussed above if it underspends relative to what is included in base rates for the Line Clearing Program.

Q. What risks would be created if deferred accounting were not authorized in the instant case?

A. Investment in all three programs is heavily driven by external factors, including customer requests the Company must address. Although the Company makes reasonable and best efforts to project investment needs in those programs, they cannot be projected with complete accuracy. As an illustrative example, the Company could project test year Asset Relocations investments of $50 million, based on a well-supported methodology, and the Commission could approve this amount for inclusion in rates. When the test year arrives, new and unforeseen Asset Relocations needs could emerge, driven by external factors, such that total Asset Relocations investments now total $55 million. In this hypothetical, the Company must make the incremental $5 million in investments. When deferred accounting is authorized, the Company has certainty that this incremental $5 million will be recoverable, even if on a deferred basis.

Conversely, without deferred accounting, this $5 million would be at risk. The Company must complete the Asset Relocations, but to keep overall investment levels in line with Commission approval, the Company would need to delay $5 million in investments in one of the planned programs, such as Reliability or Capacity. This would deprive customers of the benefits of those programs.

Furthermore, the Commission has not always approved 100% of the Company's projected investment amounts in these three programs for a variety of reasons.

If other parties argue the Company's projected investment levels in these programs are too high and the Commission agrees in a final Order, then deferred accounting supports recovery if investment levels materialize as the Company forecasted.

Deferred accounting has been approved by the Commission (through both approved settlements and orders in fully contested cases) in every rate case since Case No. U-20134, which covered a 2019 calendar test year. Since that time, deferred accounting has worked to provide for recovery of externally-driven investments that must be made and ensure the Company does not need to reduce investments in other programs that focus on proactively improving customer reliability.

IRM

Q. How did the Company identify areas of distribution investment to include in the IRM in this case?

A. The Commission most recently approved a Distribution IRM in Case No. U-21870 covering the 12-months ending April 30, 2027. In the instant case, the Company is proposing to establish a continuing mechanism that will extend the IRM for an additional two years, consisting of the test year in the instant case and the year after that, meaning the

continuing IRM would run until April 30, 2029. In the instant case, the Company is proposing to continue the IRM using the same investment categories the Commission approved in Case No. U-21870 and to add the HVD Lines Reliability sub-program as discussed below. For all proposed IRM spending, the Company proposes setting investment levels for those categories at or below those included in the test year in the instant case. See also the discussion of the IRM in Company witness Myers' direct testimony.

Q. What investments are included in the proposed IRM?

A. The IRM investments previously approved by the Commission consist of the following sub-programs:

- *LVD Lines Reliability* - Targeted Circuit Improvements and Pole Replacements;
- *Resiliency* - Fractionalization; and
- *System Protection.*

In the instant case, the Company is proposing to include the following subprogram in the IRM:

- *HVD Lines Reliability* – Line Rebuilds, Pole Top Replacements, Pole Replacements, and Pole Top Assembly Replacements.

Q. Why is the Company proposing to include the HVD Lines Reliability sub-program in the IRM?

A. The HVD Lines Reliability investment categories included in the proposed IRM are the main HVD interventions to improve electric reliability and require sustained investment to address observed system deterioration. While HVD assets historically comprise a smaller proportion of customer outage minutes compared to LVD, when HVD outages do occur they can be widespread and long in duration. As Company witness LaFrance discussed on

page 12 of his testimony, the Company continues to face deterioration of many of its HVD assets, which threatens the reliability and resilience of the entire distribution system.

Q. What level of expenditure does the Company propose to include in the IRM?

A. Based on this discussion above, the proposed expenditure level is as follows:

FIGURE 26

PROPOSED IRM EXPENDITURES ($000)

Sub-Program/ Investment Category	Approved IRM Expenditures – Year ending April 30, 2027	Proposed IRM Expenditures – Year 1 ending April 30, 2028	Proposed IRM Expenditures – Year 2 ending April 30, 2029
Lines Reliability – LVD *(Targeted Circuit Improvements, and Pole Replacements)*	$210,696	$208,660	$208,660
Lines Reliability – HVD *(Line Rebuilds, Pole Top Replacements, Pole Replacements, and Pole Top Assembly Replacements)*	N/A	$83,617	$83,617
Resiliency – Fractionalization	$11,647	$17,716	$17,716
System Protection	$4,098	$4,672	$4,672
Total	**$225,947**	**$314,665**	**$314,665**

Q. How do these proposed IRM expenditure levels compare to what was approved by the Commission in Case No. U-21870?

A. Excluding the newly added HVD Lines Reliability subprogram from the IRM, the proposed expenditure levels for Lines Reliability LVD, Resiliency – Fractionalization and System Protection are 2.3% higher in the instant case compared to the approved amounts in Case No. U-21870. This increase is lower than the 2026 inflation rate supported by Company witness Hannah L. Patton. With the inclusion of the HVD Lines Reliability Subprogram, the expenditure levels are $88.7 million, or 39.3% higher than the approved amount in case U-21870.

Q. What metrics will the Company track in the IRM?

A. The Company plans to continue tracking the same metrics as those included in Case No. U-21870, plus additional metrics for HVD Lines Reliability and report them to the Commission annually. The new metrics have been bolded in Figure 27 below.

FIGURE 27
PROPOSED IRM METRICS

Sub-Program	Proposed Metric(s)
Lines Reliability - LVD	• Miles of Targeted Circuit Improvements • Fuse Locations • LVD poles replaced
Lines Reliability - HVD	• **Miles of lines rebuilt** • **Pole tops rehabbed** • **HVD poles replaced** • **Pole top assemblies replaced**
Resiliency	• Fractionalization projects completed
System Protection	• Relays installed

Q. What dollar amounts and number of projects did the Company plan to perform during the most recently completed year of the IRM, covering the period from March 1, 2025 to February 28, 2026?

A. For the most recently completed year of the IRM, covering the period from March 1, 2025 to February 28, 2026, the Company planned to perform the number of projects with the associated dollar amounts listed below in Figure 28.

FIGURE 28
MARCH 1, 2025 TO FEBRUARY 28, 2026 IRM: TARGETED METRICS AND APPROVED SPENDING

Sub-Program	Performance Metrics	Target Units	Approved Spending
Lines Reliability	Miles of Targeted Circuit Improvements	130	$68,523,000
	Lateral fuses added	3,000	
	LVD poles replaced	300	
Resiliency	Fractionalization projects	9	$12,623,000
System Protection	Relay Panels Installed	44	$5,201,000
Total			**$86,347,000**

Q. What dollar amounts and number of projects did the Company perform during the most recently completed year of the IRM, covering the period from March 1, 2025 to February 28, 2026?

A. The actual spend and number of projects completed are listed below in Figure 29.

FIGURE 29
MARCH 1, 2025 TO FEBRUARY 28, 2026 IRM: ACTUAL METRICS AND ACTUAL SPENDING

Sub-Program	Performance Metrics	Actual Units	Actual Spending
Lines Reliability	Miles of Targeted Circuit Improvements	146	$109,822,716
	Lateral fuses added	3,033	
	LVD poles replaced	795	
Resiliency	Fractionalization Projects	7	$18,315,320
System Protection	Relay Panels Installed	21	$5,518,978
Total			**$133,657,014**

Q. Did the Company complete any additional units that are not captured in Figure 29 above?

A. Yes. The Company completed 37 miles of targeted circuit improvements and 41 fuses that were needed to complete our Fractionalization projects but are not included in the units above. The costs are captured within the seven Fractionalization projects completed in the IRM period.

Q. What drove the Company's actual spending in the most recently completed year of the IRM?

A. Several factors, including exceeding the unit target for Lines Reliability, the installation of more resilient equipment; and the use of additional contracted labor drove the Company's expenditures during the most recently completed year of the IRM. As indicated in Case No. U-21870, the Company outlined its intent to increase investment in IRM sub-programs in alignment with its Reliability Roadmap. Over the 16-month bridge period, the Company projected expenditures of approximately $170 million for these sub-programs. On a pro rata basis, this equates to approximately $127 million, which is close to the Company's IRM spending level in the test year.

Q. Why did the Company replace more poles than were included in the IRM targets?

A. Recent safety incidents, coupled with a more proactive inspection process, have led the Company to identify and complete more than double the number of pole replacements compared to initial projections. In 2025, while a Company crew was installing conductor on a new pole, an adjacent older pole with rotting at the base snapped, falling away from the line workers. This incident drove the Company to become even more proactive in identifying risks from deteriorated poles when making targeted circuit improvements and

replacing them prior to failure. As detailed in the Company's Reliability Roadmap, pole failures take roughly double the time of pole replacements, and thus replacements improve the safety as well as the cost-effectiveness of the Company's reliability work.

Q. Please explain how installing more resilient assets impacted IRM spending.

A. The Company used stronger poles and covered conductor in the last IRM period, which increased the resiliency of the grid but at a higher cost. Beginning in 2021, the Company upgraded the standard of poles installed from class 4 poles to stronger, taller class 3 and class 2 poles, which reduces the risk of failure. This work accelerated last year, as the Company installed more than twice as many class 2 and class 3 poles in 2025 compared to 2024. Additionally, the Company installed more than three times more covered conductor during 2025 compared to 2024, which adds a protective jacket to reduce the risk of outages from tree contact, wildlife, and debris. These improved standards were more expensive; for example, a class 2 pole is roughly 2.4 times more expensive than a class 4 pole. The use of these materials accounts for a portion of spending more than the original estimate of costs, particularly in the Lines Reliability – LVD subprogram.

Q. Please explain why additional contracted labor was needed for the IRM.

A. Michigan experienced a relatively higher number of icing events, tornadoes, and thunderstorm-related wind gusts in 2025, which impacted crew availability and drove the Company to use more expensive contacted labor to complete the Company's workplan. As described by Company witness Dickey in his direct testimony, in 2025, customers experienced 20% more interruptions compared to 2024, driven in part by 26 tornadoes[14] and two ice storms in the Company's service territory – one of which was the most

[14] The average number of tornadoes per year in the state of Michigan is 13.

significant ice storm in over 100 years. Restoration following these storms is time consuming and exhausting. Furthermore, the Company often must conduct damage assessment work following large storms, adding to the time that must be spent in the field due to a large storm; after the 2025 ice storm was restored, the Company spent an additional two weeks in the West Branch and Tawas areas conducting damage assessments. All of this extensive additional work led Company crew members to take time recovering from the physically taxing labor that takes them away from friends and family for extended periods. Ultimately, a storm involving one week of restoration time can affect multiple weeks of planned work.

Additionally, restoration from such large storms requires the Company to dedicate crews 24/7 for extended periods. This redirects resources from planned system improvement projects, requiring contractors to help catch up later in the year.

Overall, due to the volume and extent of damaging storms last year, the Company estimates that restoration activities consumed an additional three weeks of planned work compared to 2024. As a result, the Company hired contactors in the final five months of the IRM period, which were 25% more expensive compared to our standard contractor pool, contributing to an increase in the cost of reliability projects.

Q. What additional work did the Company complete in Lines Reliability - LVD?

A. The increased spending allowed the Company to complete an additional 15.6 miles of targeted circuit improvements, add 33 more fuses, and replace 495 more poles compared to targets.

Q. Why did the Company invest in more work than the approved targets?

A. The Company spent above approved levels in the IRM subprograms to improve the overall reliability of the grid for customers, while demonstrating the Company's ability to execute larger work plans and invest in an equitable manner. As outlined earlier in Section III of my direct testimony, the Company is increasing investment levels to mitigate the risks from severe weather. The actual spending in IRM subprograms demonstrates the Company's commitment to customers to spend no less than specified amounts to continue improving the reliability, resiliency, and equity of the grid.

Q. Why were seven Resiliency – Fractionalization projects completed compared with the projected nine projects?

A. Unforeseen challenges from supply chain issues and emergent substation failures led to the Company completing all but two fractionalization projects. Further details on these two remaining projects and their delays are included below:

- **Bennington** required the use of the Company's mobile substation to complete. However, ongoing projects and an unplanned failure at another substation requiring the Company to commit the Mobile substation fleet elsewhere stalled the substation portion of the Bennington project. Despite this delay, the Bennington project is scheduled to be completed by the end of fall 2026.

- **Eagle** experienced lead-time issues for materials such as steel poles and transformer as well as additional HVD line easements that needed to be secured before the project could begin, resulting in the project being delayed beyond 2025. These issues have been resolved, and the project is now scheduled to begin in late summer 2026.

Q. Why did the Company install 21 relay panels compared with the projected 44 panels?

A. The long cycle time of system protection projects is the main reason the Company did not complete the target of 44 panels installed. Many system protection projects typically take up to seven months to complete, which can complicate forecasting for project completion

dates. While the Company fell short of the target units, the Company exceeded the target since the completion of the IRM.

Q. How many System Protection projects has the Company completed since February 28, 2026?

A. In the two months immediately following the IRM year, the Company completed an additional 38 projects, bringing the 14-month total of completed projects to 59 projects, exceeding the units planned for the IRM.

Q. How does the IRM positively impact reliability and resiliency?

A. The Company estimates the work completed will improve annual reliability performance as measured by SAIDI excluding MEDs by 13 minutes and All-weather SAIDI by 51 minutes. Compared to the plan as filed, the completed IRM should deliver customers with an incremental nine minutes of All-weather SAIDI and two minutes of SAIDI excluding MED improvements.

Q. Did the Company deploy investments in an equitable manner?

A. Yes. The Company invested $12,430,595 of the total $133,657,014 spending, or 9.3%, in EJ communities. This IRM spending in EJ communities was greater than a proportional amount when considering the general make-up of the Company's service territory. EJ communities consist of approximately 4.1% to 9.2% of the Company's 1.9 million customers. The low-end customer count range of 4.1% represents the number of customers, approximately 78,000, living within the EJ-designated census tracts, while the high-end range of 9.2% represents the number of customers, approximately 175,000, served on the 2.5% of the Company's 61,621 low voltage primary distribution circuit miles that provide service to EJ communities.

Q. Are there any additional benefits to the IRM?

A. The IRM serves as a way ensure proactive spending on projects that are beneficial to deliver a reliable and resilient system. By ring-fencing capital, it will not be diverted to other purposes, and if not spent, customers receive the benefit of a refund.

V. HISTORICAL SYSTEM PERFORMANCE

Q. How does the Company evaluate electric distribution system performance?

A. The Company considers several reliability metrics, with SAIDI being the most prominent. Other key reliability metrics measured and tracked by the Company include SAIFI, CAIDI, and CEMI. Historical performance for these metrics is detailed in this section of my testimony.

Q. Why does the Company focus on SAIDI as part of its electric distribution spending?

A. The importance of SAIDI performance was emphasized in a September 1, 2009 Report addressed to the Michigan State Legislature, submitted on behalf of the MPSC, in accordance with Section 10p of 2008 PA 286, MCL 460.10p, where it was stated:

> In light of the research Staff conducted, the Commission finds that Consumers Energy and Detroit Edison at this time should include SAIDI, SAIFI, and CAIDI reporting (with and without major events) on a rolling five year average in a new docket that will be opened by the Commission. These indices have been proven to show the reliability of electricity in a utility's power system and are useful to the Commission in identifying utility performance trends for each specific utility on a going forward basis. The intent of the information is not to benchmark the utilities nationwide or within the state, but rather to measure performance levels of each utility against its own historical data.

Additionally, in accordance with the September 15, 2009 Order in Case No. U-16066, and a subsequent order in the same docket on January 23, 2014, the Company provides the MPSC annual performance information related to SAIFI, CAIDI, and SAIDI

with and without MEDs, on a rolling five-year average, using the industry standard IEEE method of calculation.

Q. What are the components of SAIDI?

A. SAIDI is comprised of two components: SAIFI and CAIDI.

- SAIFI is a measure of frequency of outages that is driven by system condition, system configuration, and system challenges (i.e., weather).
- CAIDI is a measure of the duration of interruptions, and is driven by system condition, the number of interruptions, resource availability, and restoration management practices.

SAIDI is calculated as follows:

$$SAIDI = SAIFI * CAIDI$$

Figure 30 shows Consumers Energy's SAIFI results over the period of 2015 through 2025, excluding MEDs.

FIGURE 30
SAIFI (2015-2025) EXCLUDING MEDS

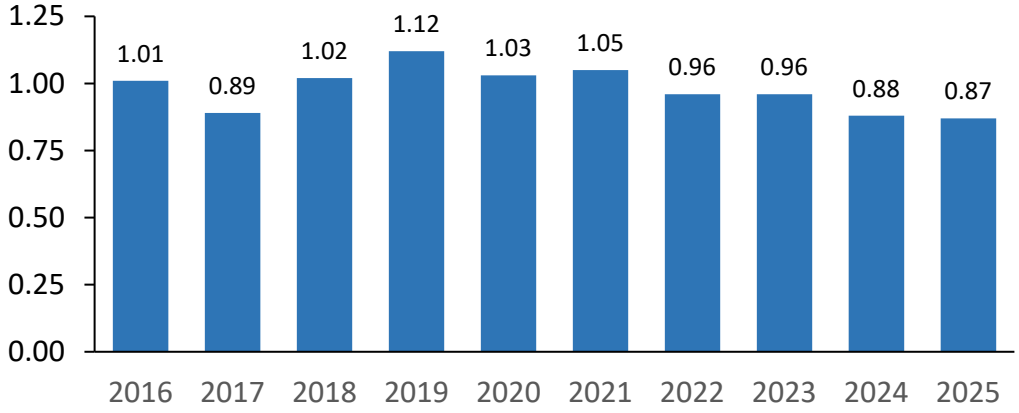
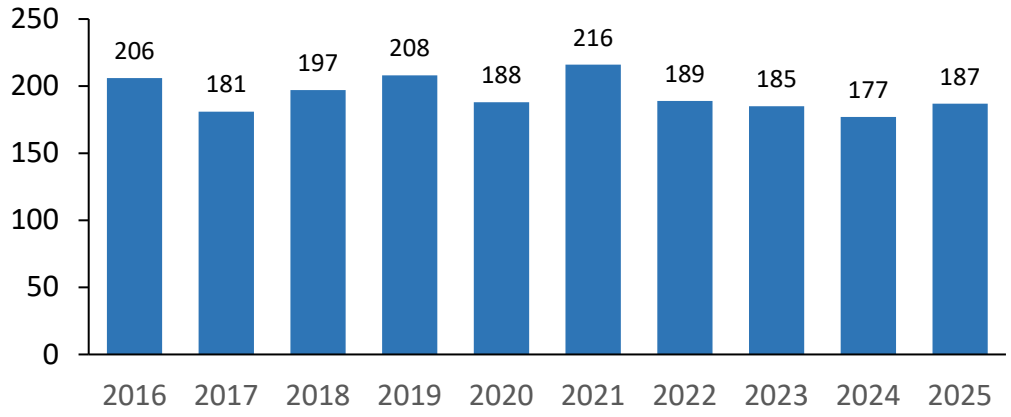


Figure 31 shows Consumers Energy's CAIDI results over the period of 2015 through 2025, excluding MEDs.

FIGURE 31
CAIDI (2016-2025) EXCLUDING MEDS

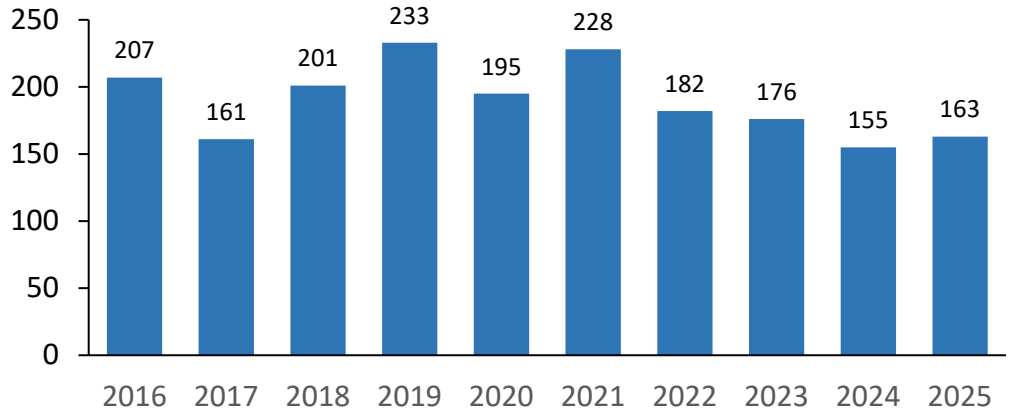


Q. What has been the recent reliability performance of Consumers Energy's distribution system?

A. Figure 32 below shows Consumers Energy's SAIDI results, excluding MEDs,[15] over the period of 2015 through 2025. MEDs are excluded from these totals to normalize performance data for unusually severe weather. The methodology for determining the level of storm activity to exclude in developing this chart is based on the IEEE *Guide for Electric Power Distribution Reliability Indices*.

[15] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

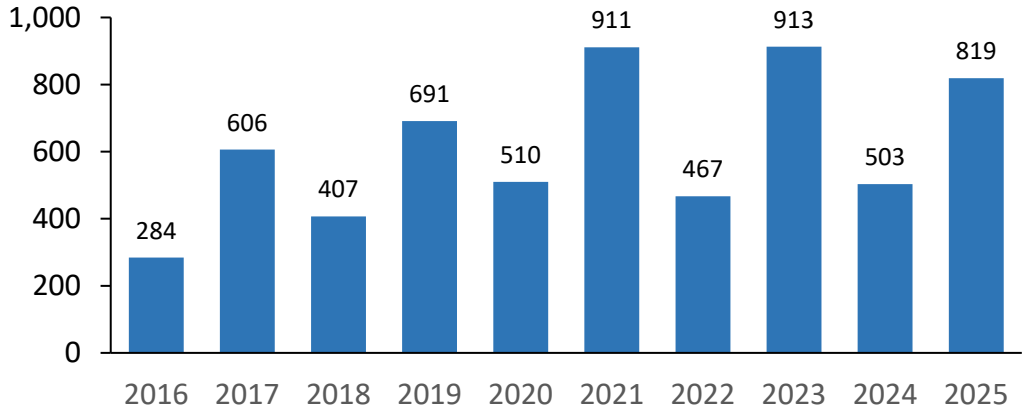
FIGURE 32
SAIDI (2016-2025) EXCLUDING MEDS



Q. If MEDs are *not* excluded, what has been the Company's recent SAIDI performance?

A. The Company's SAIDI results over the period of 2015 through 2025, *including* MEDs, are shown in Figure 33 below.

FIGURE 33
SAIDI (2016-2025) INCLUDING MEDS



Q. Please explain the year-over-year variation in SAIDI when MEDs are included.

A. The year-over-year variation is driven in part by the number of MEDs each year, as any MED is likely to result in more customer outages than on a normal day. The number of MEDs in each year from 2015 through 2025 is shown in Figure 34 below.

Compared to the middle part of the last decade, the number of MEDs has been consistently higher since 2017, an indicator of worsening weather and system deterioration.

FIGURE 34
MEDS PER YEAR, 2016-2025

Year	MED Days
2016	5
2017	8
2018	7
2019	9
2020	8
2021	11
2022	9
2023	11
2024	10
2025	13

Q. How is the Company's recent SAIDI performance broken down by system component?

A. Figure 35 below provides a breakdown of SAIDI by LVD lines, HVD lines, LVD substations, HVD substations, and the transmission system ("ITC").

FIGURE 35
SAIDI BY SYSTEM COMPONENT 2021-2025

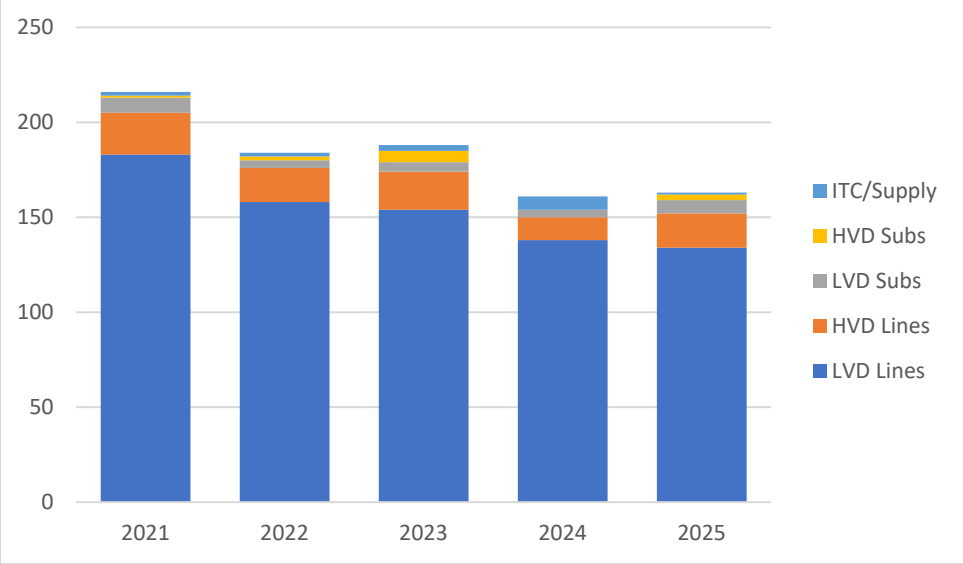


Figure 36 through Figure 38 below show the top causes of outages for HVD lines, LVD lines, and substations by illustrating the five-year average alongside the 2025 results for each cause category, with the five-year averages shown in descending order.

Green bars indicate that the 2025 results were better than the five-year average, while red bars indicate that they were worse.

FIGURE 36
HVD LINES SAIDI MINUTES BY OUTAGE TYPE - 2025

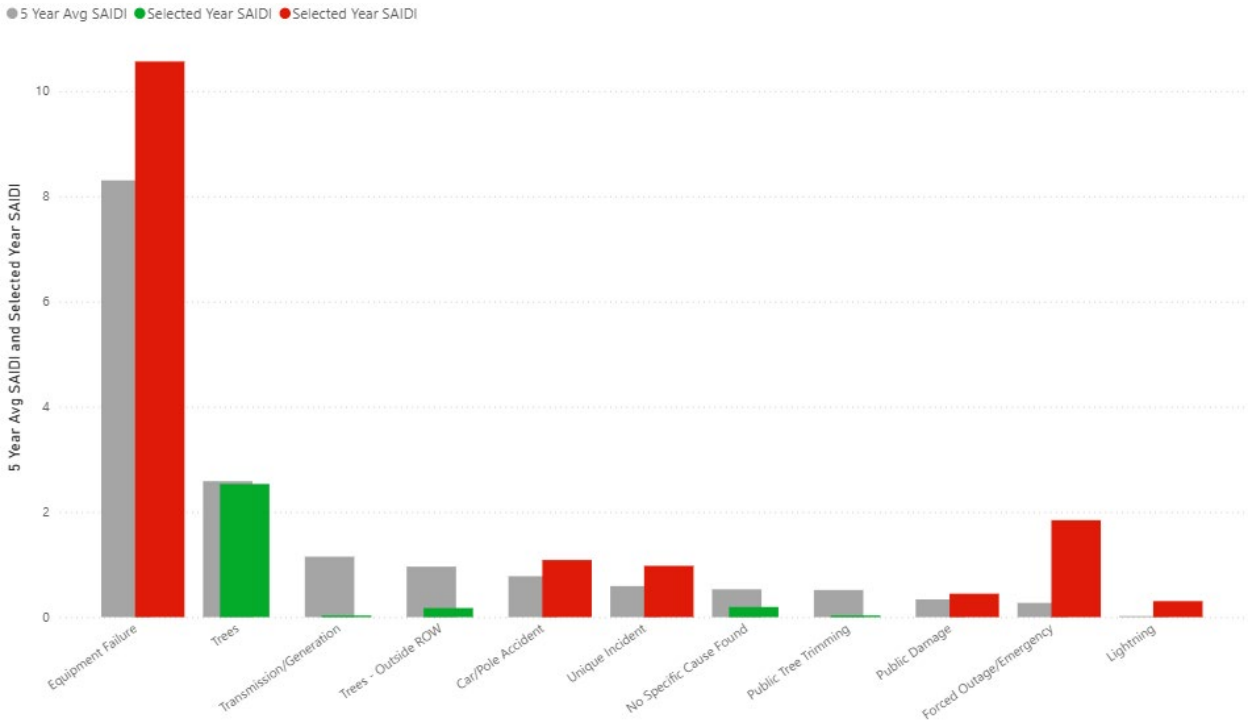


FIGURE 37
LVD LINES SAIDI CAUSES – 2025

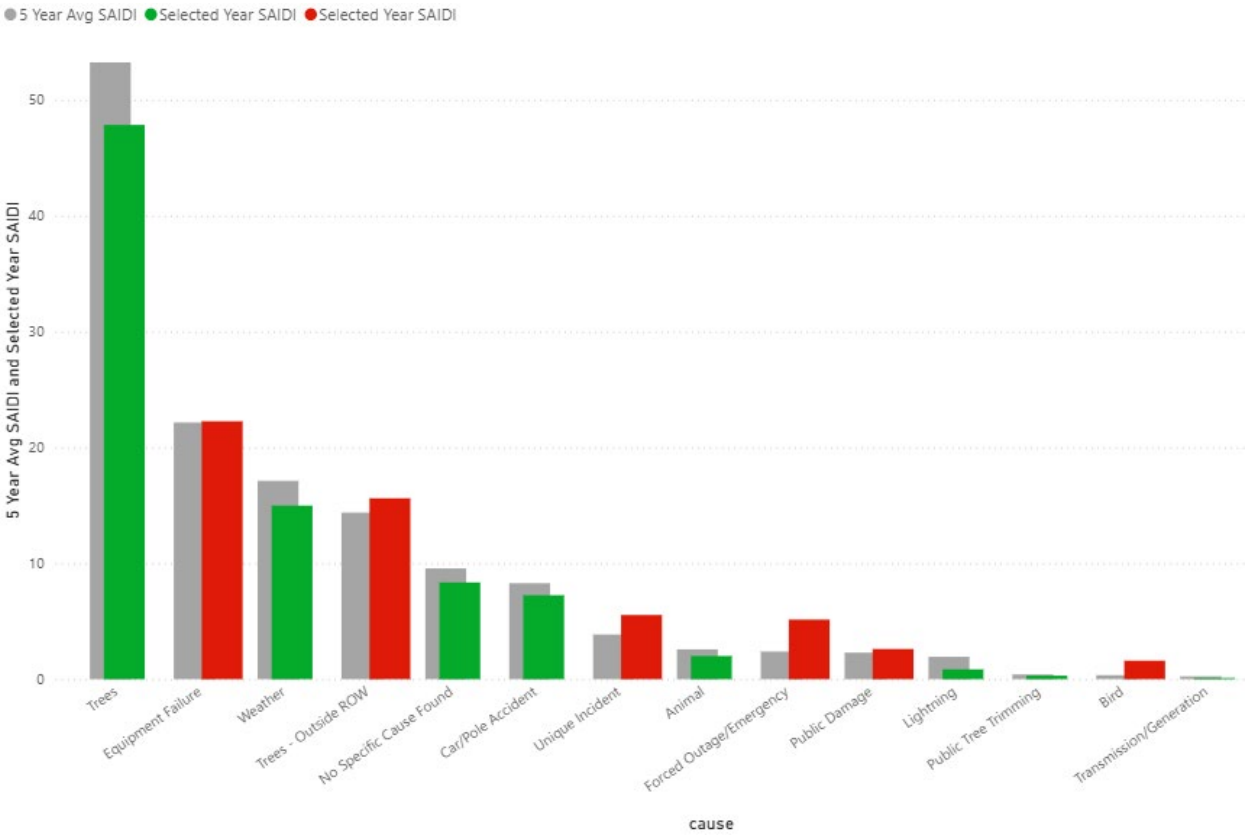
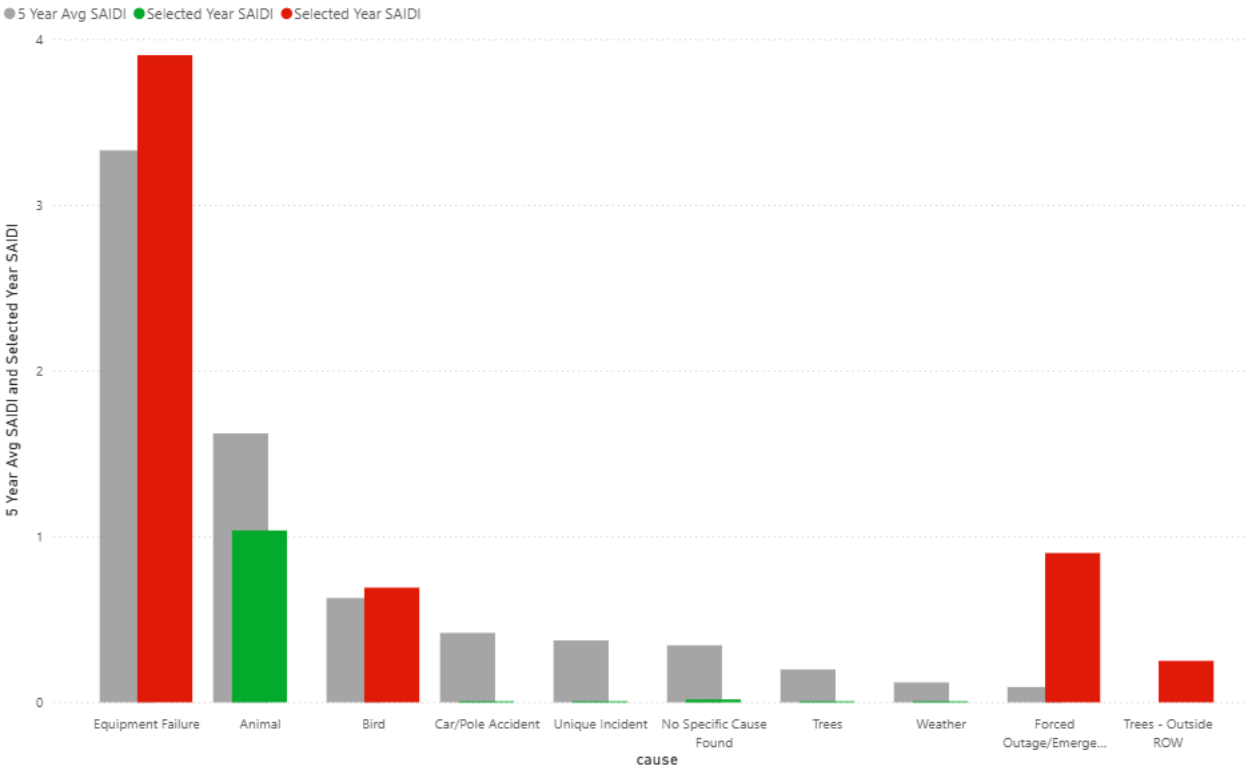


FIGURE 38
SUBSTATION SAIDI MINUTES BY OUTAGE TYPE – 2025



Q. Please describe the Company's recent experience with weather.

A. The Company monitors wind speed data from 21 different official National Weather Service stations in Michigan, as shown in Figure 39 below.

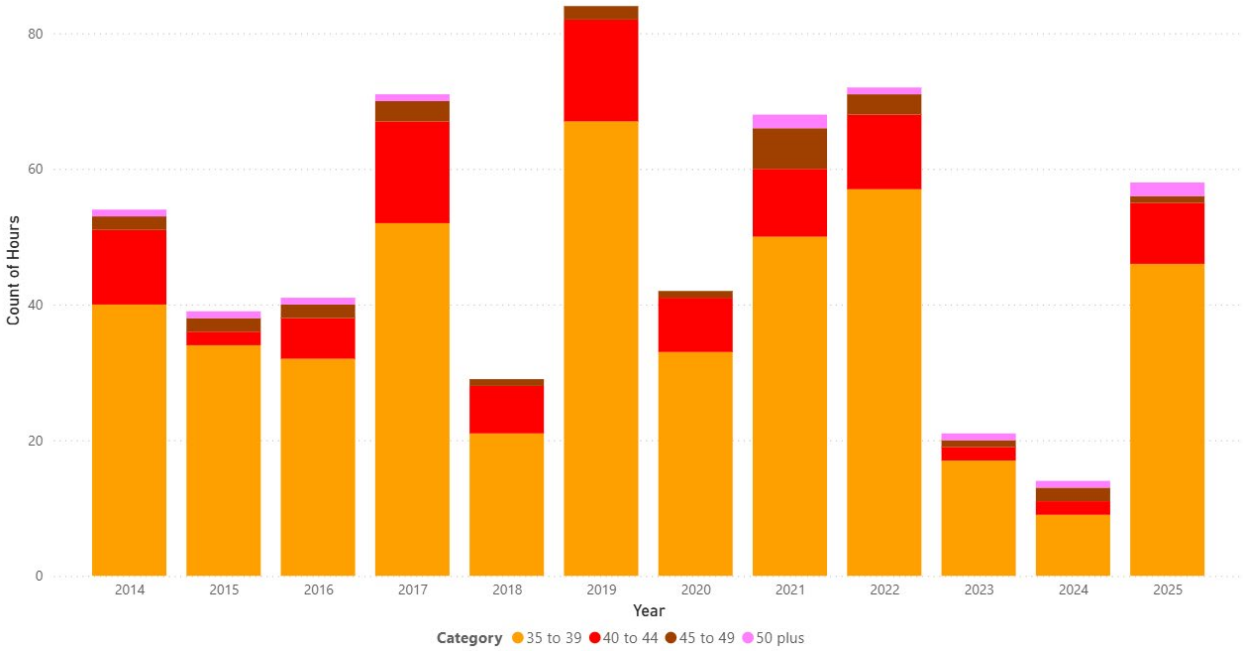
FIGURE 39
OFFICIAL NATIONAL WEATHER SERVICE WIND OBSERVATION STATIONS



In recent years, the Company has observed that wind speeds across the system have increased in severity.

Figure 40 below illustrates the number of hours, aggregated across these 21 observation stations, during which wind speed was sustained at higher than 35 mph.

FIGURE 40
STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS (2014-2025)



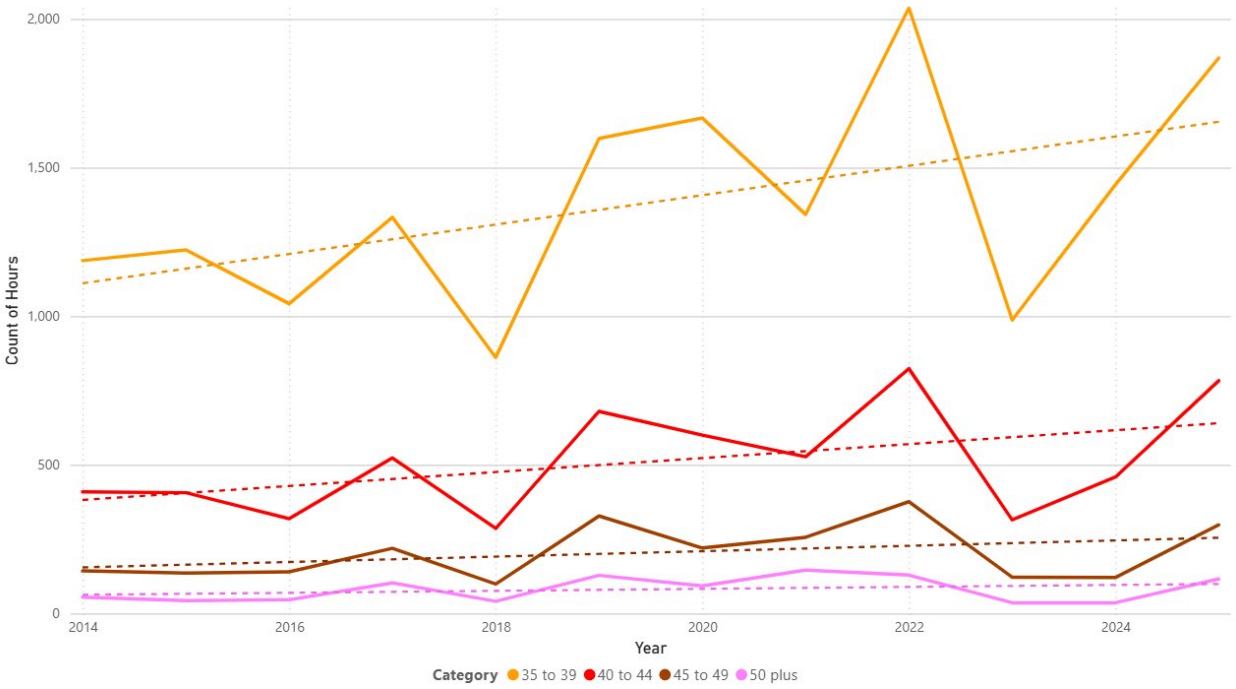
In terms of wind-caused outages, wind gusts can be even more damaging than sustained high winds, given the often-violent nature of gusts.

The National Weather Service observation stations record gusts when there are rapid fluctuations of 10 knots (11.5 mph) or more between peaks and lulls over a 10-minute window, with the gust speed being the maximum wind speed observed in that window.

Figure 41 below illustrates the number of hours, aggregated across the 21 stations, during which gusts of more than 35 miles per hour were observed, isolating the frequency of gusts exceeding 35 miles per hour in 5 mph bands.

As illustrated by the trend lines, gusts have been becoming more frequent at each of the high-speed bands.

FIGURE 41
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS (2014-2025)



The data shown in Figure 40 and Figure 41 illustrates that wind speeds and gusts have been getting increasingly worse in recent years.

Q. What conclusions does the Company draw based on this wind speed data?

A. This data highlights that, as Michigan sees increasingly extreme weather, the electric distribution system needs to be hardened against that weather to improve resiliency. It is also important to note that wind gust data does not capture the full picture of severe weather; while 2023 was less gusty than other recent years, it did feature a major ice storm and several tornadoes that drove SAIDI.

VI. TECHNOLOGY PROJECTS SUPPORTING ELECTRIC DISTRIBUTION

Q. Is the Company planning technology projects in the test year that support the Company's electric distribution strategy?

A. Yes. Company witness Stacy H. Baker is sponsoring:

a) the Integrated Energy Management Platform Optimization project; and

b) the Electric GIS Design Platform Modernization project.

Q. Please explain the Integrated Energy Management Platform Optimization project.

A. This project will reduce server 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.

Q. What issue is this project intended to address?

A. PCI Energy Solutions provides software the Company uses to fulfill the FERC requirement of communicating unit availability to the Regional Transmission Operator and to 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.

Q. What is the scope of this project?

A. The project scope includes:

1. Planning and executing data migration;
2. Designing and configuring new and existing vendor SaaS components;

3. Implementing integrations to Commercial Off-The-Shelf ("COTS") and custom systems;

4. Testing;

5. Educating and increasing the skills of employees to leverage the new vendor SaaS services; and

6. Decommissioning old infrastructure.

Q. What benefits will this project provide?

A. 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 to reduce waste and work on the most valuable items;

3. Reducing server footprint;

4. Reducing IT labor support costs; and

5. Reducing ongoing networking equipment replacement and upgrade costs.

Q. What alternatives did the Company consider?

A. Alternatives considered included:

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 servers.

2. Move to a different energy market platform. This alternative was not selected because the different platform would have fewer options and would not be able to utilize PCI's bid to bill process. PCI's bid to bill process begins with creating unit offers using inputs such as heat rates, fuel costs, emissions limits, and O&M costs, and ends with reviewing MISO settlements to calculate expected payments, charges, unit costs, and revenues, including disputing inaccurate bills.

3. Move to the vendor SaaS. This alternative was selected as the Company will utilize the latest technology and optimize operational support.

Q. What is the cost of this project?

A. The Integrated Energy Management Platform Optimization project requires $12,841,281 in capital ($2,273,025 Rough Order of Magnitude adjusted capital) and $1,091,157 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Integrated Energy Management Platform Optimization project?

A. The projected expenditures were estimated based upon previous work for that product family and anticipated software costs.

Q. Please explain the Electric GIS Design Platform Modernization project.

A. This project is replacing the existing design software for LVD with a new solution that will be fully integrated into the ESRI R GIS platform already in use by the Company.

This new solution will leverage GIS asset data to generate engineering designs. It will allow engineering teams to have a single source and format to view asset data, construction drawings, and redlines in both the back office and the field.

This change will further enable improvements to the mobile platform in quality of data used by the closeout team. This will also reduce the back-end posting effort by using the native GIS data format, thereby improving data quality by reducing re-keying of data. The current design software creates waste in three areas for many teams, including LVD Engineering, Field Leaders, and Customer Energy Management ("CEM") Service Designers.

Q. What problems is this project intended to address?

A. First, 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 re-draw designs in GIS already created, and prevents optimization of the work process.

Second, it is not able to integrate with SAP to automatically order materials based on the design.

Third, the current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not geo-referenced to the exact location and cannot fully use redlining capability, which causes a significant impact to data quality and crew performance.

The project scope includes:

1. Installing a new solution that will integrate to GIS;
2. Using 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.

Q. What benefits will this project provide?

A. This project creates value for the Company by:

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. Enabling integration with SAP; and

4. Using the capabilities of the next generation GIS platform to be delivered through an in-progress business case.

Q. What alternatives did the Company consider?

A. 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 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, and costs.

3. Implement a GIS based solution. This alternative was selected because a new solution will use existing geospatial platform on premise, and will move the Company to a single data format that will enable both field and back office employees.

Q. What is the cost of this project?

A. The cost of the Electric GIS Design Platform Modernization project is $2,018,702 in capital expenditures ($1,614,962 Rough Order of Magnitude adjusted capital) and $136,794 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Electric GIS Design Platform Modernization project?

A. The projected expenditures were estimated based on previous work for this product family and anticipated software costs.

VII. ELECTRIC DISTRIBUTION O&M EXPENSES

Q. What is included in the Company's distribution O&M spending?

A. The Company's O&M spending supports its capital investments through maintenance and operation of grid infrastructure, plus engineering and design work required to execute

projects, and provides for restoration of service to customers following interruptions. Forestry Line Clearing O&M is discussed by Company witness Stewart, and Service Restoration O&M is discussed by Company witness Dickey.

The Company's distribution O&M spending includes: (1) funding for the Company's ongoing distribution Operations and Engineering functions; and (2) funding for certain internal organizations, such as training and equipment repair, that support both functions.

Summaries of the distribution O&M expenses are provided in Exhibits A-90 (EMD-6) and A-93 (EMD-9), and a five-year average of O&M expenses is provided as Exhibit A-94 (EMD-10).

Q. What is the overall recent trend in the Company's distribution O&M?

A. In 2025, the Company's distribution O&M was $283,019,000, as shown in Exhibit A-94 (EMD-10), line 37, column (f). For the years 2021 through 2025, actual O&M expenses were taken from Consumers Energy's internal reporting records. The Company's projected test year distribution O&M is $321,665,000, as shown in Exhibit A-94 (EMD-10), line 37, column (l). This test year projection is based on the sum of each individual O&M line item, which I will discuss in the subsequent sections of my direct testimony.

Q. Do test year projected O&M expenses represent continuing functions and activities?

A. Yes. The Company projects that the functions and activities represented by the expenses for the test year will be similar and consistent with the functions and activities that were performed in 2025, with any exceptions explained below.

Q. Please explain Exhibit A-92 (EMD-8).

A. Exhibit A-92 (EMD-8) presents the amounts of the projected O&M expenses in my other O&M exhibits, and identifies an inflation component that reflects how much inflation affected O&M spending levels between the 2025 historical year and the test year in this case.

In this exhibit, column (b) shows the historical O&M expense. Column (b) shows the amounts to which an inflation rate or merit increase rate was applied for the year ending December 31, 2025. Column (c) shows the prorated merit and inflation increase for the period of January 1, 2026 through April 30, 2028. Amounts that were projected using other methods are included in column (d). Column (e) is the projected test year O&M and is the sum of columns (b), (c), and (d). Column (e) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibits A-93 (EMD-9) and A-94 (EMD-10).

However, the Company's Electric Distribution O&M has generally not been developed by simply taking 2025 actuals and then applying inflation rates to them. Each O&M sub-program's projected expenses are developed using methodologies specific to the sub-program, which I will discuss throughout this O&M section of my testimony.

The purpose of Exhibit A-92 (EMD-8) is simply to identify an inflation rate and an inflation component so that those who wish to consider alternative inflation rates can make comparisons.

Q. Is it possible to calculate unit costs for any O&M sub-programs?

A. Not in a consistent way. Some O&M sub-programs are largely based on headcount, where the expenses will be heavily based on the number of employees. Others are based largely

on projected work volumes. However, many O&M expenses correspond to fixed costs that do not vary with any kind of unit. Many O&M sub-programs involve some kind of blend of inputs, being based on some combination of headcount, work volume, and fixed or one-time costs.

VIII. ELECTRIC OPERATIONS

Q. Please detail the O&M programs which comprise Electric Operations.

A. As shown in Exhibit A-90 (EMD-6), Electric Operations includes the following programs:

- Service Restoration - LVD;
- Low Voltage Distribution;
- High Voltage Distribution;
- Grid Operations & Restoration;
- Performance Innovation & Strategy;
- Management & Chargebacks; and
- Work Management & Customer Delivery.

A. Service Restoration

Q. Please describe the O&M work and expenses related to the Service Restoration sub-program.

A. Company witness Dickey discusses the entirety of this sub-program in his direct testimony. Service Restoration O&M expenses are projected to be $241,667,000 in the bridge period and $192,571,000 in test year. O&M dollars in this sub-program support activities described within Company witness Dickey's direct testimony.

B. Low Voltage Distribution

Q. Please describe the O&M expenses related to the LVD Program.

A. The Company's LVD O&M Program focuses on the inspection, design, repair, and monitoring of low-voltage distribution equipment. The Company's LVD Operations and Meter Services O&M spending supports several demand-driven programs that are essential to the front-line operation of the distribution grid. The LVD Program is comprised of ten sub-programs:

- LVD Engineering;
- LVD Lines Reliability;
- Corrective Maintenance;
- Staking;
- Meter Services;
- Streetlighting;
- Service Calls;
- LVD Field Operations Expenses;
- LVD Operations; and
- Underground Workforce.

LVD Engineering

Q. Please describe the LVD Engineering Program shown on Exhibit A-94 (EMD-10), line 2.

A. Expenses in this program cover salaries and expenses for the Company's LVD Engineering organization, which includes the Company's LVD Planning, LVD Design, and Joint Pole Rental teams.

Q. Please explain LVD Engineering.

A. LVD Engineering expenses primarily include the O&M portion of salaries, business expenses, and training for LVD Engineering employees. LVD Engineering personnel perform security inspections on at least one-half of the overhead LVD system each year, and initiate corrections to defects they find. They plan, develop the scope, and initiate projects that:

- Correct LVD system planning criteria violations found by performing power flow analyses on the Company's LVD circuits;
- Improve reliability for LVD infrastructure;
- Serve C&I customer load additions connected to the LVD system; and
- Further the modernization of the distribution system.

They also support the Company's stray voltage mitigation program by performing inspections to validate proper installation and operation of the installed mitigation equipment.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 2, column (l), the Company is projecting to spend $5,486,000 in the test year.

LVD Lines Reliability

Q. What work activities are carried out in the LVD Lines Reliability O&M sub-program?

A. The LVD Lines Reliability O&M sub-program supplements the LVD Lines Reliability capital sub-program through inspection and maintenance of LVD lines and LVD Metro assets. As illustrated in the Reliability Roadmap, IEEE recommends a certain cadence for inspecting different components of the LVD system, and repairing any issues that are

identified. This includes general pole and line inspections, padmount inspections, and inspections of devices and equipment like reclosers, switches, and capacitors.

Q. Please describe general LVD line and pole inspections.

A. General LVD line inspections are conducted as discussed in the testimony of Company witness Partlan. Issues identified in those inspections that are not capital replacements are corrected through this O&M program; issues that do require capital replacements are generally addressed in the LVD Lines Demand Failures sub-program. Some examples of this O&M work include:

- Replacing a fuse link to put a fuse back into service or correct system protection issues, including device reach and coordination between devices;
- Moving a jumper on a line or device to balance load among phases or reconfigure the customer's service;
- Bringing assets up to existing standards, such as by moving lightning arrestors to the load side of the transformer cutout;
- Replacing damaged/stolen components, such as sections of copper down grounds that have been stolen or broken crossarm braces;
- Adding or correcting existing labels for devices in the field to match Company records; and
- Adding animal mitigation due to past animal related outages.

This also includes groundline pole inspections to identify individual LVD poles that need to be replaced. Groundline pole inspections are discussed in more detail in Company witness Partlan's testimony.

Q. What is included in padmount inspections?

A. The exterior of padmounted equipment (including the base) is visually inspected on a two-year cycle for any signs of leaking oil, holes that expose electrical components, missing transformer locks, or missing labels. If found, the holes are patched, and labels are

replaced. If equipment is unrepairable, replacement of equipment is done under the LVD Lines Demand Failures sub-program as described in the testimony of Company witness Partlan.

Q. What work is done on devices and equipment?

A. Maintenance of devices and equipment is required to maintain the benefits of these devices and equipment. The Company can remotely monitor equipment equipped with a modem to identify when it is not functioning properly. When this occurs, the device or equipment is investigated to determine the cause. If the equipment or device is unrepairable, replacement of equipment is done under the LVD Lines Demand Failures capital sub-program.

Equipment without a modem needs to be inspected on a cycle to ensure it is functioning properly. This equipment includes a portion of electronic reclosers, and all Gang Operated disconnect switches. Electronic reclosers without a modem need the control unit checked for error codes. If an error is found, the recloser is investigated to determine the cause. If the recloser is unrepairable, replacement of recloser is done under the LVD Lines Demand Failures capital sub-program.

All electronic reclosers require battery replacement to ensure the battery is working correctly and the electronic controls of the recloser operate as intended. Batteries should be replaced on a four-year cycle.

Gang Operated disconnect switches need to be inspected for damage or erosion and cycled to ensure they work properly when needed for load transfers or isolation of damage. If damage or erosion is found or the switch does not cycle correctly, it can be repaired or replaced, depending on the issue.

Q. How does this work benefit customers?

A. This work benefits customers by reducing outages caused by failed equipment, improving public safety, improving power quality, getting the full life out of installed equipment, and reducing electric load.

LVD line and pole inspections proactively identify failed equipment, providing a reliability benefit to customers by improving the condition of system equipment when failed components are replaced and placing the system back into a normal operating condition, eliminating an outage in the future. It is estimated the average order saves 21,000 customer-outage-minutes.

Padmount inspections provide public and environmental safety benefits. The Company reduces the risk of the public encountering energized equipment by fixing holes and replacing locks. Identifying oil leaks ensures a minimal amount of transformer oil is released to the environment and timely correction of leaks.

Maintenance of devices and equipment ensures the devices operate as intended and are available for use when needed. It also allows the Company to get the benefits from the full life of the equipment.

When electronic reclosers have errors, they may not operate as intended. This could mean causing outages to customers when no sustained fault is present or causing the upstream device to open instead, causing more customers to be impacted by an outage. On average, electronic reclosers on the LVD lines feed 670 customers, which means they have a large impact on customers. Timely battery replacements ensure the electronic reclosers have power and can be operated by line crews, improving restoration time.

Capacitor banks help to improve power quality for customers and reduce losses on the electric system by improving the power factor of the electric system. They are one of the components of the Company's CVR project, as discussed in Company witness Partlan's direct testimony. Keeping capacitor banks operational is integral to the success of the CVR program.

Gang Operated Switches are used to isolate damage and transfer load from a circuit over to the adjacent circuit. They are regularly used in both planned and emergent events where equipment or lines need to be taken out of service. They are used to keep as many customers restored as possible during planned work, and to more quickly restore customers during emergent events.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 3, column (l), the Company is projecting to spend $7,066,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is based on the Company's costs to complete the inspection and maintenance work described above. In particular, the Company is projecting to spend $785,492 in the test year on maintaining disconnect switches, $4,678,056 on the O&M portion of the groundline pole inspection program, and $516,771 on padmount inspections. The remaining $1,085,220 will be spent on the other LVD inspections defined in the Reliability Roadmap.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. Historical spending levels in this sub-program were insufficient to complete all of the IEEE-recommended work. The Company identified this issue when developing the Reliability Roadmap in 2023, and began developing a plan to increase needed maintenance work going forward.

Additionally, the increase in spending in this sub-program compared to recent levels is primarily attributable to a change in accounting interpretation, rather than any expansion in program scope or increase in inspection activity. Effective at the start of the test year on May 1, 2027, the Company is adopting an updated interpretation of applicable accounting guidance—addressing the concerns discussed by Staff witness Anna N. N. Schiller in her direct testimony in Case No. U-21870—to expense all costs associated with the inspections discussed above as O&M. Historically, a portion of these costs had been capitalized when performed in conjunction with capital work.

This change reflects a different interpretation of generally accepted accounting principles ("GAAP"), which places emphasis on expensing inspection activities conducted to evaluate asset condition and maintenance needs. While the Company continues to believe that its prior capitalization practices were reasonable and appropriate under its former interpretation, it is implementing this revised treatment to address Staff's accounting concern and to improve consistency and transparency in cost classification going forward. Importantly, this change affects only the accounting treatment of the costs, not the nature, scope, or frequency of the inspection activities themselves. The impact of this accounting change is an increase of $2,957,209 in O&M expense in the test year.

Corrective Maintenance

Q. What work activities are carried out in the Corrective Maintenance O&M sub-program?

A. The Corrective Maintenance sub-program supports customer- and field-generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements. This most prominently consists of splicing wire on primary and secondary LVD lines. This also consists of responding to underground faults, which takes longer than responding to those on the overhead system.

This sub-program ensures adherence to regulatory standards while advancing the Company's safety and reliability goals through targeted maintenance designed to remediate safety hazards and system deficiencies. Its most significant application is in wire-down response, where it supplies the splicing capabilities required to safely and efficiently restore damaged conductors.

Q. How does this work benefit customers?

A. The Corrective Maintenance sub-program improves public safety and reliability of the system by responding to customer reported concerns, and damage from other incidents, most critically by responding to the safety issues posed by broken wires.

While in some circumstances the Company will replace equipment and infrastructure to upgrade and improve the system, there are times when replacement is not the most cost-effective option. In these instances, a minor repair or modification that improves safety or reliability of the system can be made. For example, if a pole has minor damage, then the Company may make a minor repair to quickly restore a customer, and then not need to fully replace the pole until a later time.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 4, column (l), the Company is projecting to spend $5,163,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined by accounting for the expected level of work orders. This sub-program consists largely of labor costs, and is based on projected workplan hours to complete the work orders.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending compared with the 5-year average is being driven by an increase in labor costs. Each year, the Company's electric service workers receive a cost-of-living adjustment and union-negotiated merit increases in pay. Notably, the projected test year expense is less than the expense in the 2025 historical year.

Staking

Q. Please describe the O&M expenses related to the Staking & Locating sub-program.

A. The Staking & Locating sub-program involves Company labor and contractor services for the staking and locating of the Company's electric distribution facilities, in accordance with the MISS DIG law (Public Act 174 of 2013 ("Act 174")), a key component of securing public and employee safety. Work is typically performed by a contracted outside service vendor on a multi-year contract with the Company.

Q. Please discuss the work activities in the Staking and Locating Sub-Program.

A. The Staking and Locating sub-program includes the following work activity categories:

- **Outside Services - Dedicated:** Contractor costs are included in the test year projection for staking and locating activities performed under the Dedicated Staking programs, under which contractors work solely for the Company.

- **Company Labor:** Volumes and hours are included in the test year projection for Company labor to support abnormal operating condition efforts.

- **Licenses, Permits & Fees**: Includes fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.

- **System:** Use of Irth Solutions UtiliSphere to enable ticket management and reporting for contracted staking and locating, MISS DIG ticket risk scoring to enable more effective and efficient excavator intervention, and work plan management and reporting.

Q. Has the Company made any changes to the above work activity categories in recent history?

A. Historically, the Company also had "Outside Services" contractor costs for staking and locating activities under a shared resource model, in which contractors would also work for other parties besides the Company. In 2023 and 2024, the Company started using dedicated contractors who only work for the Company. Based on realized performance improvements, the Company began transitioning to a fully dedicated staking contractor model in December 2024 and completed the transition in March 2025. Therefore, in the test year in this case, there are no costs for Outside Services for shared contractors.

Q. What benefits does the Company anticipate going forward?

A. The dedicated contractor model will continue to deliver improved timeliness and support reduction in the number of damages caused by third-party staking and locating which supports public safety. Additionally, the Company believes dedicated contractors will continue to improve communication and partnership with the contractors.

Q. Please provide a breakdown of Staking and Locating sub-program expenses.

A. The Staking & Locating sub-program expenses for 2025 and the test year in this case are identified in Figure 42 below:

FIGURE 42
STAKING AND LOCATING SUB-PROGRAM PROJECTION BREAKDOWN BY ACTIVITY TYPE

Work Type	2025 Actual	Test Year
Outside Services – Staking and locating	$194,661	$0
Outside Services – Dedicated electric staking and locating	$11,206,413	$14,659,550
Company labor	$10,896	$10,847
Licenses, Permits & MISS DIG Fees	$610,304	$717,296
Total Program	**$12,022,273**	**$15,387,693**

Q. What is the basis for determining the $15,387,693 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units). The primary drivers for increased spending in the test year in this case include:

(a) increase in the cost per ticket under the contracts with staking contractors ($1,683,532 total increase) includes dedicated model expansion;

(b) anticipated contractor volume increases ($1,574,943 total increase); and

(c) increases in MISS DIG 811 membership fees ($106,992 total increase).

Q. Describe the test year forecast for volume and unit costs.

A. An anticipated unit cost increase is included in the test year projection for contractor services, in alignment with historical data and the requirement for enhanced capability to manage increased demand in performance and increasing labor costs.

The staking completed by an outside contracted vendor is billed based on contractual unit costs.

An anticipated volume increase of approximately 6% annually is included in the test year projection relative to 2025 contractor services. This is in alignment with the

historical data and staking forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume increases are shown in the following table:

FIGURE 43
Historical Data and Unit Cost Staking Forecasts

Contractor Stake & Locate Services		
	Base Unit Forecast (units)	Base Unit cost ($/unit)
2024 Actual	433,137	$13.32
2025 Actual	530,810	$21.48
2026 Projected	557,722	$23.30
2027 Projected	596,040	$24.10
2028 Projected	625,842	$24.72

The Statewide MISS DIG 811 Annual Ticket Requests table below shows the change in staking volumes realized year over year.

MISS DIG 811 data[16] shows a continuous growth in staking and locating ticket requests for the entire state of Michigan, except for a small decline in 2020, which appears to be a temporary result of COVID-19 pandemic business impacts. Given a projected increase in staking volumes tied to expansion of rural broadband internet infrastructure, growth is expected to further increase.

The following is the historical and projected Statewide MISS DIG 811 annual ticket requests:

[16] https://www.missdig811.org/about/who-we-are/about-miss-dig.html

FIGURE 44
MISS DIG ANNUAL GROWTH

Statewide MISS DIG 811 Annual Ticket Requests		
Year	**Annual Ticket Requests**	**% Change From Prior Year**
2016	814,303	
2017	872,896	7.2%
2018	923,993	5.8%
2019	1,015,753	9.9%
2020	994,573	-2.1%
2021	1,088,030	9.4%
2022	1,093,021*	1.0%
2023	1,202,992	10.1%
2024	1,327,894	10.4%
2025	1,448,398	9.07%
2026 Forecast	1,549,786	7% assumed
2027 Forecast	1,658,271	7% assumed
2028 Forecast	1,774,350	7% assumed

*Volume impacted by MISS DIG 811 Pelican implementation

Q. Please describe the Company's concerns with the increase in staking ticket volumes and proposed recommendation.

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optics and other infrastructure work, the actual staking demand the Company experiences in 2027 could be above the Company's staking volume forecast. While the Company attempts to forecast staking volumes with a high degree of accuracy, the largest factors influencing expenses in these programs are externally driven. As a result, the Company requests it continue to be allowed to defer for refund or recovery of any O&M expenses for this program, below or above amounts included in rates for the test year related to changes in the volume of tickets; this treatment was approved by the Commission in Case No. U-21870. This request would avoid potential constraints on other important programs if higher than anticipated staking costs outside the Company's control are incurred. It would also prevent customers from paying for costs that were not incurred if staking volumes are below forecasted levels.

The Company is basing its current deferral request mainly on one high-speed internet infrastructure grant program administered by the Michigan High-Speed Internet Office ("MIHI") located within the Prosperity Division of the Department of Labor and Economic Opportunity. The program is the Broadband Equity, Access, and Deployment Program ("BEAD").

Q. Describe the Company's proposed deferral mechanism.

A. The Company is proposing a continuation of the deferral mechanism approved in Case No. U-21870 based on the variability in staking volume with the following adjustments for the test year. For the test year, the Company expects unit ticket volume of 604,136 at a unit cost of $24.27. The ticket volumes in the test year are forecasted as follows:

- May – December of 2027 to equal 434,119, or 72.8% of 2027 total shown in Figure 43
- January – April 2028 to equal 170,017, or 27.2% of the 2028 total shown in Figure 43

The equation to determine the refund or recovery for the test year is proposed to be:

- Refund (-) /Recover (+) = (actual staking volume – 604,136) * $24.27

The purpose of the deferral mechanism is to address future uncertainty about staking volumes, and that uncertainty is due in large part to potential variability tied to the larger BEAD rural broadband program. Therefore, the Company is not proposing a Refund or Recovery limit at this time.

Q. Should a cap be applied to the Refund or Recovery?

A. No. A volumetric cap should not be applied to the deferral. The Company does not have control over the volume of work requests it is obligated to perform, making such a cap impractical. This variability is evidenced by 2025 performance, where the Company projected 478,176 units under Case No. U-21585 but ultimately completed 530,810 units.

After several years of relatively stable staking and locating volumes, the rapid expansion of broadband infrastructure has introduced increased volatility in ticket demand. This shift has reduced predictability, as demonstrated by the 17% variance between projected and actual volumes in 2025.

Q. Please describe the test year costs related to dedicated locating.

A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, dedicated locating is the act of placing marks to indicate approximate facility location in response to a MISS DIG ticket requested in advance of excavation activity. An anticipated increase in volume and costs is included in the test year projection for dedicated locating. This includes resources to locate *only* Consumers Energy facilities, contrasted to the previous method of vendors locating several other additional external facilities. This focus substantially mitigates public safety, damage, timeliness, quality, and communication risks with excavators in some of the highest areas for staking requests for Consumers Energy, encompassing 100% of requests starting in April of 2025.

Q. Please explain the MISS DIG cost increase.

A. MISS DIG 811 costs were assessed in 2023 by the MISS DIG Board and adjusted as of January 2024 based on actual utilization for members, which resulted in an increase for the Company.

Meter Services

Q. What work activities are carried out in the Meter Services O&M sub-program?

A. This O&M sub-program funds Electric Meter Operations ("EMO"), whose expenses are partially offset by first-set and retirement credits of both electric meters and metering transformers within the Meter Credits O&M sub-program. EMO responds to customer-

initiated and Company-generated orders for installation, replacement or repair, and inspection of new and existing metering installations to ensure customers have a safe, reliable, and accurate metering installation. This sub-program also installs, removes, and maintains demand response and power quality installations.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring that all customers, from residential to commercial and industrial ("C&I") and generation and transmission interconnections, have reliable and accurate billing information. Additionally, smart meters are required for customers to participate in programs like time of use rates and to see their usage in the customer portal.

Metering also impacts reliability. Metering infrastructure is aging, with some metering transformers more than 60 years old. The Company continues to inspect and maintain these transformers, but eventually more intentional replacements of wiring and other components are needed to prevent meter failures that would cause outage minutes.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 6, column (l), the Company is projecting to spend $13,527,000 in the test year on meter services.

Q. How were these spending amounts determined?

A. These spending amounts were determined by considering projected work. The Company projects a volume of work based on historical data and expected growth from areas like New Business. Workload projections assume a certain number of hours to do given work, based on historical productivity, which is translated into expenses for meter installations.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The higher level of spending is due to a shift in workload from more capital-intensive meter replacements to meter maintenance, which is driven in part by meters being further along in their life cycle. In addition, the average standard labor rate in the test year is 21% higher than the average standard labor rate across the past five years.

Streetlighting

Q. What work activities are carried out in the Streetlighting O&M sub-program?

A. Streetlighting O&M supports the personnel and materials necessary to complete streetlight maintenance activities. Examples of Streetlighting O&M expenses include underground fault investigations, minor repairs including conductor splicing and replacement of photo cells, and shield installation on light-emitting diode luminaires.

Q. How does this work benefit customers?

A. Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. This work complements the capital investment in Company-owned streetlights.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 7, column (l), the Company is projecting to spend $2,107,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were developed using historical O&M expenses and planned work orders, which were consolidated into a workplan that places greater emphasis on extended outage investigation and repair activities.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The higher level of spending compared with the 5-year average is being driven by increased time spent investigating, locating, and repairing underground-fed lights. Activities associated with failure investigation, locating, and repair of underground-supplied lights include additional hydro excavation, on-site trouble shooting, and splicing. The Company's test year projection is less than the 2025 actual test year expense.

Service Calls

Q. What work activities are carried out in the Service Calls O&M sub-program?

A. In the Service Calls sub-program, the Company responds to various types of requests from customers, including disconnections and reconnections, undergrounding service lines, upgrading service lines to higher capacity, and installing temporary service lines to support house construction. Customers pay for some requested work, but not for disconnections and reconnections, and the Company incurs O&M costs not billable to the customer for all types of Service Call work. The Company estimates, based on 2025 historical numbers, that employees will respond to approximately 39,000 discrete service calls annually. This O&M sub-program funds these responses.

Q. How does this work benefit customers?

A. This work benefits customers by responding to their expressed specific needs for electric service.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 8, column (l), the Company is projecting to spend $4,906,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined primarily by reviewing the program's historical actual expenditures. The estimated level of activity in the Company's workplan continues to reflect the previous year's completed work; however, for this cycle, total program spending is based on the prior year's actual costs adjusted by a compounded inflation rate of 6.2%. As with previous methodology, projected costs are directly tied to the underlying workplan assumptions. The Company translates expected workplan activity into projected labor hours and applies current labor cost rates accordingly. In addition to projected labor costs, the Company also incorporates non-labor spending, which is forecasted by applying the same 6.2% compounded inflation factor to the prior year's actual non-labor expenses.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in the test year is primarily driven by the increase of inflation year over year from the historical period to the test period at an inflation factor of 6.2%.

LVD Field Operations Expenses

Q. What work activities are carried out in the LVD Field Operations Expenses O&M sub-program?

A. The LVD Field Operations Expenses sub-program consists of the cost of overhead expenses in support of the Company's in-field LVD operations team. For electric line workers, this sub-program covers most of their expenses outside of salaries: travel expenses, meals, and field mobility costs for things like phones and internet connectivity in the field.

Q. How does this work benefit customers?

A. This work benefits customers by enabling employees to do their jobs in the field, completing reliability projects and other work that benefits customers. These expenses ensure that employees can travel to where work is needed.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 9, column (l), the Company is projecting to spend $3,096,000 in the test year.

Q. How were these spending amounts determined?

A. These costs are planned annually, based on the expected costs to support an in-field operations team to conduct the various activities required for supporting the safe, reliable, and efficient operations of the electric distribution system. In general, projected spending is heavily based on historical actuals, with adjustments based on apprentices hired that will increase total headcount, and based on any increases in items such as the cost of travel and telecommunications.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in the test year is primarily due to the fleet telematics contract being renewed. Fleet telematics devices collect operations, safety, productivity, and maintenance data; transmit that data wirelessly; and produce dashboards and reporting to manage fleet safety, performance, and maintenance accordingly. The new contract is structured as a monthly fee per device, and devices are installed on Company fleet vehicles and trailers. The previous contract included the monthly fee as part of the upfront installation cost, resulting in increased cost given the new contract.

LVD Operations

Q. What work activities are carried out in the LVD Operations O&M sub-program?

A. This sub-program includes the salaries and expenses of the supervision and leadership (at the first-line supervisor level) for the LVD Electric Operations group, to ensure safe operation of facilities and adherence to Company policies.

Salaries and expenses fund O&M Supervision in Electric LVD, and the Electric Joint Committee (governing training for apprentices).

Q. How does this work benefit customers?

A. This work benefits customers by funding the field supervision necessary for completing work in the field, and the supervision required in certain training situations to ensure the Company continues to have an adequate workforce.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 10, column (l), the Company is projecting to spend $2,452,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on projected headcounts and the salaries for those employees.

Q. Are there changes in spending in this sub-program compared to recent levels?

A. The spending remains relatively consistent with recent levels.

Underground Workforce

Q. Please describe the O&M work related to the Underground Workforce Program.

A. The Underground Workforce Program provides for the training of the employees who conduct both the undergrounding work in subdivisions and new business services,

relocations, and reliability projects, plus future overhead to underground conversions the Company expects to continue into the test year of the instant case as described by Company witness Partlan. The group can also perform replacement of failed underground and new underground construction for LVD overhead lines replacement.

Q. What is the Company's projected test year spending level for this sub-program?

A. As shown in Exhibit A-94 (EMD-10), line 11, column (l), the Company is projecting test year spending of $2,601,000.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on the training for new business and failure work, training for expansion of the overhead to underground program, and expenses and tools. These costs are as follows:

- $1,205,000 for training the workforce needed to perform undergrounding for new business and failure work;
- $1,000,000 for training the workforce necessary for expanding the overhead to underground program described by Company witness Partlan; and
- $400,000 for expenses and tools.

C. <u>High Voltage Distribution</u>

Q. Please describe the work related to the High Voltage Distribution Program, as shown in Exhibit A-90 (EMD-6), line 3.

A. The Company's HVD O&M expenses consist of demand sub-programs, the associated Electric Equipment Repair Center located in Alma and the inspection, design, repair, and monitoring of HVD equipment sub-programs. Additionally, the expense for Dissolved Gas Analysis testing of LVD and HVD substation equipment is included in this sub-program.

Q. What are the sub-programs contained within the HVD O&M expense program?

A. The sub-programs, as shown in Exhibit A-94 (EMD-10), lines 13 through 22, are:

- Lines Reliability – HVD;
- Substations Reliability – LVD;
- Substations Reliability – HVD;
- HVD Engineering;
- HVD Lines Demand;
- LVD Substations Demand;
- HVD Substations Demand;
- Alma Equipment Repair;
- HVD Field Operations Expense; and
- HVD Operations.

HVD Lines Reliability

Q. What work activities are carried out in the HVD Lines Reliability O&M sub-program?

A. The Company's HVD Lines Reliability O&M sub-program includes the expense portion of the Company's HVD pole inspections, which occur on a 12-year cycle; and annual Motor Operated Air Break Switches ("MOABS") tests. Each of these is fundamental for maintaining HVD line assets. MOABS are a key component of Supervisory Control and Data Acquisition on the HVD system, and are tested annually to ensure the controls are in proper working order. Also, the batteries are replaced every three to four years or sooner, as needed. The 12-year pole inspection cycle is discussed in the direct testimony of

Company witness LaFrance. The inspection data and information gathered through this O&M sub-program is key information used to assist in identifying line capital projects.

Q. How does this work benefit customers?

A. Both pole inspections and MOABS testing identify assets (poles and switches) for repair or replacement. These repairs and replacements reduce the number of outages that would occur if this work were not performed (in the case of pole replacements) or greatly reduce the impact of outages when they do occur (in the case of MOABS). Company witness LaFrance details the benefits of HVD Lines Reliability investments supported by these inspections in his direct testimony.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 13, column (l), the Company is projecting to spend $344,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is based on the historical average spend in this sub-program, specifically HVD pole inspections, testing of MOABS, and MOABS battery replacements.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in this sub-program compared to recent levels is primarily attributable to a change in accounting interpretation, rather than any expansion in program scope or increase in inspection activity. Effective May 1, 2027, the Company is adopting the updated interpretation of applicable accounting guidance—addressing Staff witness Schiller's concerns in her direct testimony in Case No. U-21870—to expense all of these inspection-related costs as O&M as previously described in my testimony. Historically, a

portion of these costs had been capitalized when performed in conjunction with capital work. The impact of this accounting change is an increase of $168,670 to O&M.

Substations Reliability – LVD and HVD

Q. Please describe the general work associated with both the LVD and HVD Substations Reliability sub-programs.

A. These two sub-programs provide proactive inspections and maintenance to equipment to maintain operational functionality of LVD and HVD substation assets, as well as the Company's Metro assets.

While *proactive* work is done in the LVD and HVD Substations Reliability O&M sub-programs, *reactive* work to fix assets already broken is performed by this same workforce in the LVD and HVD Substations Demand O&M sub-programs described later in my direct testimony. Though there are separate line items for LVD and HVD substations, the same Company workforce addresses both asset groups using a common plan - in short, a single substation operations workforce performs work in four different O&M sub-programs.

As discussed in the Reliability Roadmap, the Company is increasing its total substation O&M spending across the four sub-programs to better align with the *Electric Substation Reliability Guidelines* ("ESR-1"). Historical levels of funding have not been adequate to complete sufficient inspections or to address maintenance backlogs.

Substation inspections are particularly important because they allow the Company to monitor the health of transformers, load tap changers, oil circuit breakers, and other critical substation equipment. If equipment is not monitored, the risk of failure increases,

and these kinds of substation equipment failures can result in lengthy and widespread outages lasting until repairs can be made.

Additionally, ongoing substation maintenance provides these benefits:

- Increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation;
- Decreased costs by avoiding emergency repairs, allowing for more predictability in the capital workplan; and
- Extension of asset life, avoiding emergent capital replacements and allowing for more predictable future capital investments.

Q. Please describe the work in the LVD Substations Reliability O&M sub-program as shown in Exhibit A-94 (EMD-10), line 14.

A. The LVD Substations Reliability O&M sub-program supports substation and substation equipment inspections, recloser and circuit breaker test operating, and substation battery maintenance. This O&M sub-program also supports Metro system inspections. This sub-program includes required environmental inspections under the Spill Prevention, Control and Countermeasure ("SPCC") Program. These equipment inspections are based on manufacturers' recommendations, industry best practices, and years of experience with the equipment in question, and include maintenance activities such as lubrication and changing of filters. Neglecting these inspections can result in premature equipment failure and additional capital expense.

Funding for 80% of the total HVD and LVD substation mowing and weed-spraying activities is included in this sub-program. These activities typically involve two weed-spray applications per year, along with a five-month mowing schedule—from May through September—at a frequency of twice per month. Due to unusually vigorous and

widespread weed growth observed statewide in recent years, a second weed-spray application was added in 2025.

Issues identified by inspections or patrols under this program are corrected through work orders in the LVD Substations Demand O&M sub-program, the LVD Substation Reliability capital sub-program, or the LVD Substation Demand Failures capital sub-program. Increased spending in this program will allow for a larger number of substation equipment inspections to be carried out.

Q. Please describe the benefits to customers provided by the LVD Substations Reliability sub-program.

A. The LVD Substations Reliability sub-program includes inspections and maintenance that help avoid LVD substation outages. Bi-monthly patrol inspections of LVD substations identify issues that cannot be found through other means. In recent years, such inspections identified items such as copper theft from the substation, cracked and broken insulators, a burned up recloser control, and a broken pole—all of which could affect system operation and potentially result in outages.

On average, the total SAIDI minutes due to LVD Substation outages is 6.8 minutes. The average LVD substation outage resulted in 0.14 SAIDI minutes (the equivalent of 1,414 customers out of service for 334 minutes). In 2025, the most significant SAIDI outage was on the Fordyce substation. This single event resulted in 0.73 minutes of SAIDI (2,173 customers interrupted for 1,619 minutes).

Consequently, each outage avoided has a significant benefit to system reliability. Deteriorated or damaged electrical equipment can be prone to dangers such as electrical arcing and/or explosions, resulting in danger to customers and Company employees.

Maintaining equipment allows the system to be operated as intended at its most efficient level, and reduces the need for capital costs to rehabilitate or replace substations as well as decrease the frequency and duration of outages.

Q. Please describe the projected O&M expenses related to the LVD Substations Reliability sub-program, as shown in Exhibit A-94 (EMD-10), line 14.

A. The Company is projecting LVD Substations Reliability O&M expenses of $5,136,000 in the test year.

Q. Why is projected spending increasing relative to recent historical actuals for LVD Substations Reliability O&M?

A. As noted above, historical funding levels in this sub-program have not been sufficient to complete substation inspections on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in the substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this.

Q. Please describe the work related to the O&M expenses for the HVD Substations Reliability sub-program as shown in Exhibit A-94 (EMD-10), line 15.

A. The goal of the Company's HVD Substations Reliability O&M sub-program is to maintain the safety and reliability of HVD substations.

This program includes several activities, such as monthly substation equipment inspections, breaker test operating, and substation battery maintenance. This program includes required environmental inspections due to the SPCC Program.

Additionally, funding for 20% of the total HVD and LVD substation mowing and weed spraying expenses are included in this sub-program. Issues identified by inspections or patrols under this program are corrected using orders created under the Substation Demand—HVD O&M Program, HVD Substation Reliability Program, or HVD Lines and Subs Failures Program.

Q. Please describe the O&M expenses related to the HVD Substations Reliability sub-program, as shown in Exhibit A-94 (EMD-10), line 15.

A. The Company is projecting HVD Substations Reliability O&M expenses of $3,120,000 in the test year.

Q. Why is projected spending increasing relative to recent historical actuals for HVD Substations Reliability O&M?

A. As with LVD Substations Reliability O&M, historical funding levels in this sub-program have not been sufficient to complete substation inspections and maintenance on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in all four substation O&M programs relative to historical averages to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this. Note that in the case of HVD Substations Reliability O&M, projected test year costs are higher than the recent average but are in line with levels from 2025.

Q. Please describe the benefits to customers provided by the HVD Substations Reliability sub-program.

A. The HVD Substations Reliability sub-program includes inspections and maintenance that are expected to avoid HVD substation outages. On average, the total SAIDI due to HVD substation outages is 1.8 minutes. The average HVD substation outage resulted in 0.39 SAIDI minutes (the equivalent of 5,379 customers experiencing a 133-minute outage) but can be much larger in scope when they occur (such as the outage at Morrow Substation in January 2019 resulting in 2.686 SAIDI minutes). Consequently, each outage avoided has a significant benefit to system reliability. Additionally, there are public and Company safety benefits from having periodic inspections of HVD substations as electrical equipment that is deteriorated or damaged can be prone to dangers such as electrical arcing and/or explosions.

Lastly, maintaining equipment allows the system to be operated as intended and at its most efficient level, which keeps costs down and can decrease the frequency and duration of outages.

HVD Engineering

Q. Please describe the HVD Engineering Program as shown on Exhibit A-94 (EMD-10), line 16.

A. The HVD Engineering Program includes salaries and expenses for the distribution functions of the Company's HVD Engineering organization, including HVD planning work, HVD design work, system protection, and project engineering.

Q. Please explain HVD planning work.

A. HVD planning expenses primarily include the O&M portion of salaries, business expenses, and training for personnel performing HVD planning functions.

HVD planning personnel plan, develop the scope, and initiate projects that correct HVD system planning criteria violations found by performing power flow analyses on the Company's HVD system, and to correct HVD system issues related to poor reliability or poor asset health. They plan, develop the scope, and initiate projects that:

- Improve reliability for HVD infrastructure; and
- Serve large industrial customer load additions connected to the HVD system.

They also perform generator interconnection studies, plan and develop the scope, and initiate projects to connect DERs to the HVD system and LVD substations. HVD planning O&M expenses also include payment of the North American Electric Reliability Corporation ("NERC") annual dues for the Company, and expenses related to helicopter inspections of the HVD system.

Q. Please explain HVD design work.

A. HVD design personnel create designs for connecting new industrial customers to the HVD system as well as designs for projects that improve reliability or upgrade the capacity of the HVD system for both lines and substation projects.

Q. Please explain system protection planning work.

A. System protection planning expenses primarily include the O&M portion of salaries, business expenses, and training for system protection planning personnel, relay maintenance costs, and relay scheme communications costs.

System protection planning employees are responsible for the protection systems across LVD, HVD, and generation. These responsibilities include:

- Developing the engineering specifications and standards for protection systems;
- Creating and maintaining the Company's electric short circuit models that are used when performing protective device coordination studies;
- Developing settings on protective devices installed across the Company's electric system;
- Developing maintenance programs for protection devices; and
- Ensuring compliance with applicable NERC standards.

System protection planning employees analyze electric system events that caused HVD and LVD circuits, substation components, and generating plant equipment to open via protective relay activation to ensure that fault conditions were recognized properly, and that electric system interrupting devices (like substation circuit breakers) operated correctly.

System protection planning employees also work closely with HVD planning personnel when performing generator interconnection studies to ensure interconnecting generators install proper protective relays and schemes that coordinate with Company protective relays and schemes.

Q. What are the Company's projected test year expenses for Electric Distribution – HVD?

A. As shown in Exhibit A-94 (EMD-10), line 16, projected test year spending is $7,031,000.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in comparison to recent levels is to account for increasing amounts of planned HVD work in the Reliability Roadmap and increasing expenses for HVD planning to support this.

Additionally, the increase in spending in this sub-program compared to recent levels is primarily attributable to a change in accounting interpretation as described in the LVD Lines Reliability O&M section above. Specifically, the Company is now recording all helicopter inspection costs in O&M, whereas historically a portion of these costs had been capitalized. Because these helicopter inspection activities—used to perform aerial assessments and identify system conditions across large sections of the network—were previously split between capital and O&M, reclassifying the full cost to O&M represents a shift in how the costs are recorded, not an increase in the level of work being performed. The impact of this accounting change is an increase of approximately $600,000 to O&M expense in the test year.

Finally, the increase in spending in this sub-program compared to recent levels is due to the new helicopter inspection contract that increased approximately $440,000 in the test year.

HVD Lines Demand

Q. What work activities are carried out in the HVD Lines Demand O&M sub-program?

A. The Company's HVD Lines Demand O&M sub-program includes certain expenses for repairs to 46 kV and 138 kV lines equipment. Specifically, these expenses address non-capital HVD failures identified in routine inspections or emergent customer-impacting

events. For example, if a tree falls on a line and breaks it, a crew will fix the line, and this work is not capitalized. The HVD system is the backbone of the electric distribution system, and the work in this sub-program mitigates large and long outages that would otherwise come when these assets fail.

This sub-program also includes associated on-call costs for line crews. The Company has five or six crews on call at any given time to ensure they can be quickly deployed following outages. When large storm events are predicted, the Company may obtain additional or enhanced on-call crews. Activities in this program are typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrols, ground patrols, and investigation of trip and reclose occurrences.

Q. How does this work benefit customers?

A. This sub-program supports preventative maintenance with repairs and upgrades of non-capital assets, downed wires, as well as splice and connector replacements. These repairs are completed to prevent outages and improve system integrity and reliability. In particular, the Company's 46 kV system is approximately 37% radial. On radial lines, repairs must be completed before all customers can be restored. These outages can have a significant impact on SAIDI which can often exceed 0.3 minutes to more than 1 minute of SAIDI depending on what repairs are needed. When the Company is able to isolate and restore all customers before repairs occur, SAIDI can be minimized to under 0.3 minutes of SAIDI per incident in the majority of cases.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 17, column (l), the Company is projecting to spend $1,500,000 in the test year.

Q. How was this spending amount determined?

A. The spending amount was developed based on the anticipated number of HVD line work orders the Company expects to complete during the test year. These work orders are driven primarily by the findings and requirements that result from both the ground patrol and helicopter inspection programs.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The Company has increased the frequency of its HVD line inspection activities compared to recent years and has expanded its use of advanced inspection technologies—particularly infrared imaging and drone-based assessments—to identify system anomalies more effectively. As a result, the number of anomalies discovered has risen, which in turn has generated additional work orders necessary to address these findings. This upward trend in inspection-driven corrective work is reflected in the historical spending shown in Exhibit A-94 (EMD-10), line 17, columns (d) through (f), and continues through both the bridge period and test years.

Substations Demand – LVD and HVD

Q. Please describe the general work associated with both the LVD and HVD Substations Demand sub-programs.

A. These two sub-programs respond to failures resulting in customer outages or equipment outages, poor testing results (e.g., infrared inspections, oil sampling, etc.), and substation

asset management database algorithms, supporting the Company's safety and reliability objectives by ensuring customer and electric system safety, outage restoration, and repairs to equipment to maintain operational functionality of LVD and HVD substation assets.

As noted earlier in my direct testimony, these two sub-programs employ the same Company workforce and overall workplan, along with the LVD and HVD Substations Reliability O&M sub-programs, and the Company is projecting increased spending in these sub-programs to ensure the Company can complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap.

Q. Please describe the work related to the LVD Substations Demand sub-program.

A. The Company's LVD Substations Demand O&M sub-program includes expenses for emergent restoration and corrective maintenance on LVD substation equipment and facilities. This program includes work on the equipment, facilities, infrastructure, and property associated with LVD substations.

In addition, the Company is required to correct situations where equipment in substations violates National Electric Safety Code ("NESC") requirements for working space clearance (typically between live components in control panels and other panels, walls, etc.). The Company committed to complete all this work by the end of 2028 under a 10-year plan.

Q. Please describe the O&M expenses related to the LVD Substations Demand sub-program as shown in Exhibit A-94 (EMD-10), line 18.

A. The Company is projecting LVD Substations Demand O&M expenses of $5,800,000 in the projected test year.

Q. Why is LVD Substations Demand O&M spending increasing relative to historical levels?

A. As with the two Substations Reliability O&M sub-programs, historical funding levels in this sub-program have not been sufficient to complete substation inspections on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in all four substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this. More inspections in the two Substations Reliability O&M sub-programs will result in more issues to address in the two Substations Demand O&M sub-programs. Historically, every $1 spent in a Reliability O&M sub-program on inspections has yielded $1.70 in maintenance needs in the corresponding Demand O&M sub-program.

Q. Please describe the work related to the HVD Substations Demand sub-program.

A. The Company's HVD Substations Demand O&M sub-program includes expenses for unplanned and emergent restoration, as well as corrective maintenance on HVD and Strategic Customer substation equipment and facilities. In addition, the Company is required to correct several situations where equipment in substations violates NESC requirements for working space clearance (typically between live components in control panels and other panels, walls, etc.). The Company committed to complete all this work by the end of 2028 under a 10-year plan.

Q. Please describe the O&M expenses related to the HVD Substations Demand sub-program, as shown in Exhibit A-94 (EMD-10), line 19.

A. The Company is projecting HVD Substations Demand O&M expenses of $5,000,000 in the projected test year.

Q. Why is HVD Substations Demand O&M spending increasing relative to historical levels?

A. As with the other substations O&M sub-programs, historical funding levels in this sub-program have not been sufficient to complete substation inspections on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work. The Company is increasing the O&M spending in all four substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs. In 2025, the Company began the year with approximately 2,500 orders, added an additional 947 orders, and completed 1,258 orders reducing the backlog by approximately 300 orders resulting in approximately 2,200 backlog orders at the beginning of 2026. The projected spending level in the instant case will continue to reduce the maintenance backlog.

Q. Please describe the benefits to customers provided by the LVD and HVD Substations Demand sub-programs.

A. Work identified through substation inspections reduces the potential for outages from unplanned events. These corrections are relatively quick and simple (e.g., lubricating bearings, realigning a switch, or adding SF6 to a gas circuit breaker) and can be achieved through spending in this program. Occasionally, the issues require equipment replacement that would be covered under one of the capital programs (such as HVD Lines and

Substations Rehabilitation or HVD Lines and Subs Failures) and in some cases, such as a circuit breaker repair, an evaluation must be performed to determine if a procedure such as rebuilding the breaker is more cost effective than replacing the unit. Either way, it is almost always more cost efficient to perform the work in a planned manner than waiting for the unit to fail. This provides value to the customer and provides the best reliability. The projected spending increases will allow the Company to perform additional inspections and corrective maintenance.

Alma Equipment Repair

Q. What work activities are carried out in the Alma Equipment Repair O&M sub-program?

A. The Company's Alma Equipment Repair O&M sub-program, based at the Company's Alma Service Center, includes maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment. End-of-life retirement of failed and aged electrical equipment such as regulators, reclosers, and pole top transformers is also handled through this program. The sub-program also includes activities such as substation equipment acceptance testing and ensuring compliance with all environmental regulations regarding the handling, storage, and disposal of equipment containing polychlorinated biphenyl ("PCBs").

Q. How does this work benefit customers?

A. These activities are considered base level maintenance for system reliability and emergency response to demand outages. In particular, mobile substations need to be properly maintained so they are in good working order and can be deployed for field use

when needed. The Alma Equipment Repair O&M sub-program can also identify savings for customers. For example, quickly repairing equipment like regulators, when possible, represents savings when compared to capital replacements; when the Company identifies damaged materials, Alma Equipment Repair employees assess if it can be fixed and returned to service or if it must be scrapped and replaced, based on relative costs.

Additionally, the Alma Equipment Repair O&M sub-program supports safety by ensuring safe disposal of hazardous substances, and offsets some costs by selling used transformer oil to parties who can use or recycle it.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 20, column (l), the Company is projecting to spend $475,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on anticipated headcount levels and the volume of work expected to be done. Both headcount and workload have been relatively consistent in this sub-program in recent years, and projected test year spending is closely in line with recent actuals. Test year spending is slightly higher than the five-year average to account for increased maintenance volume, with more mobile substations having been purchased by the Company.

HVD Field Operations Expenses

Q. What work activities are carried out in the HVD Field Operations Expenses O&M sub-program?

A. The Field Operations Expenses sub-program consists of the cost of overhead expenses in support of the Company's in-field operations team. For electric line workers, substation

workers, and electric service workers, this sub-program covers most of their expenses outside of salaries: travel expenses, meals, and field mobility costs for things like phones and internet connectivity in the field.

Q. How does this work benefit customers?

A. This work benefits customers by enabling employees to do their jobs in the field, completing reliability projects and other work that benefits customers. These expenses ensure that employees can travel to where work is needed.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 21, column (l), the Company is projecting to spend $363,000 in the test year.

Q. How were these spending amounts determined?

A. These costs are planned annually, based on the expected costs to support an in-field operations team to carry out the various activities required for supporting the safe, reliable, and efficient operations of the electric distribution system. In general, projected spending is heavily based on historical actuals, with adjustments based on apprentices hired that will increase total headcount, and based on any increases in items such as the cost of travel and telecommunications.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by the Company's increased headcount in its field operations workforce, which in turn increases the total expenses incurred.

HVD Operations

Q. What work activities are carried out in the HVD Operations O&M sub-program?

A. This sub-program includes the salaries and expenses of the supervision and leadership (at the first-line supervisor level) for Electric Operations, to ensure safe operation of facilities and adherence to Company policies.

Salaries and expenses fund O&M Supervision in Electric System Substation, Electric System HVD and Substation Construction.

Q. How does this work benefit customers?

A. This work benefits customers by funding the field supervision necessary for completing work in the field, and the supervision required in certain training situations to ensure the Company continues to have an adequate workforce.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 22, column (l), the Company is projecting to spend $1,307,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on projected headcounts and the salaries for those employees.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is driven by increased number of supervisors to support the growth in the workforce needed to deliver the Reliability Roadmap.

D. Grid Operations & Restoration

Q. What are the sub-programs contained within the Grid Operations & Restoration O&M expense program?

A. The Grid Operations & Restoration program encompasses the core operational and metering support functions that enable effective day-to-day management of the electric distribution system. This includes Meter Credits, which ensures accurate billing adjustments; Meter Tech & Management System Support, which maintains metering technology and associated data systems; Smart Energy Machine-Type Communication ("MTC"), which supports advanced metering and communication capabilities; Grid Management, which provides real-time system oversight and operational coordination; and Grid Automation, which deploys automation tools to improve reliability, enhance situational awareness, and support faster service restoration. Collectively, these sub-programs provide the technical and operational foundation necessary for safe, efficient grid operations.

Meter Credits

Q. What work activities are carried out in the Meter Credits O&M sub-program?

A. When the Company buys meters, it capitalizes them the first time they are installed (including labor) in the LVD Metering capital sub-program, discussed by Company witness Partlan. In addition to the direct cost for electric meters and metering transformers, a first-set credit value is included to offset the cost of labor for installation. When electric meters and metering transformers are purchased and received, the first-set credit value for each meter is totaled at the end of each month and credited back to O&M for the installation labor. When electric meters and metering transformers are retired, the cost of removal

credit is totaled at the end of each month and credited back to O&M for the final removal labor. The first-set credit and retirement credit make up this sub-program.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 24, column (l), the Company is projecting $5,016,000 in meter credits in the test year.

Q. How were these spending amounts determined?

A. Total credits are based on projections for new meter capital purchases and meter retirements. The credit rate calculation is determined monthly, which is calculated considering labor, vehicle loadings, and non-premise cost. These amounts are then apportioned by an electric mix factor (a portion of the meters are installed by EMO and others by Distribution) and then multiplied by the average time required to either install (for first set credits) or remove (for retirement credits) a meter. This calculation varies based on meter or transformer type.

As an example, for November 2025, for a single-phase, 200 Amp, smart meter, the calculated first-set credit was as follows:

Figure 45
Example of Credit Rate Calculation

	Distribution	EMO
Standard Labor Rate	$ 103.82	$ 80.24
+		
Standard Labor Rate * Vehicle Loading		
Standard Labor Rate	$ 103.82	$ 80.24
Vehicle Loading	0.22	0.48
	$ 22.84	$ 38.51
+		
Standard Labor Rate * Non-Premise		
Standard Labor Rate	$ 103.82	$ 80.24
Non-Premise	0.7	1.72
	$ 72.67	$ 138.01
=		

Loaded Hourly Rate		$ 199.34	$256.76
	*		
Electric Meter Mix		0.32	0..68
	=	$ 63.79	$ 174.60
Blended Loaded Hourly Rate		$	89.17238.39
	*		
Average Install Time (hr)		0.23	
	=		
1st Set Credit Rate		$	54.83

The retirement credit rate is calculated using the same methodology, with the exception that instead of the average install time, the average remove time is used, in this case, 0.13 hr, resulting in a retirement credit rate of 31.00 per unit.

Q. What is driving the reduced credits in this sub-program compared to recent levels?

A. The level of credits in this sub-program continues to decline as inventory is carried over from previous years of meters. Because of this carried over inventory, the Company is not making as many capital purchases of meters. This trend in the overall decrease in capital meter purchases can be seen in Exhibit A-87 (EMD-3), line 9.

Meter Technology and Management System Support

Q. What work activities are carried out in the Meter Technology and Management System Support O&M sub-program?

A. The Meter Technology and Management System Support O&M sub-program funds the MTC activities to support the Metering capital sub-program. Activities performed by the MTC include:

- Electric meter and metering transformer testing for accuracy and function in accordance with MPSC rules governing meter accuracy and testing requirements;
- Evaluation of new metering and meter communications technology;
- Lifecycle assessment testing;

- Device management, including metering equipment purchase planning and meter work order troubleshooting and support;
- Order fulfillment for field operations for metering equipment;
- Daily interrogations of the Company's AMI electric meters;
- Maintenance of hardware and software firmware in the AMI electric meter population; and
- Smart Energy Operations Center ("SEOC") Operations.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring all customers, from residential to C&I and generation and transmission interconnections, have reliable and accurate billing information. This operation maintains the health of the electric smart meters, and enables customers to participate in programs, such as the time-of-use program, and the ability to have more granular information about their energy consumption through a Web portal. The testing performed at the MTC keeps the Company in compliance with MPSC metering rule requirements, as the annual meter routine sampling program is performed at the MTC. Additionally, the sub-program funds technical assessment of new metering and communications equipment related to meters, and assessment of new devices that can benefit customers through programs such as load monitoring or load control devices.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 25, column (l), the Company is projecting to spend $1,290,000 in the test year.

Q. How were these spending amounts determined?

A. The level of spending for this program is made up of three components: Salaried labor, Union labor, and business expenses. The spending for each year is based on the current headcount, including any approved hiring for vacancies with the applicable labor costs for each, including inflation and expected labor increases. In addition, the projected spending

for this program considers any planned promotions and known business expenses that are planned for the subsequent years. Spending in this program has remained relatively flat for most of the last five years with minimal variability in year over year expenses.

Smart Energy MTC

Q. What work activities are carried out in the Smart Energy MTC O&M sub-program?

A. The Smart Energy MTC sub-program consists of four components:

1. Communications backhaul for both Smart Meters and Cellular-Under-Glass legacy meters. Specifically, the Company's electric smart meters all provide billing determinants and metering events through cellular communications, and the Company pays cellular charges per meter monthly.
2. Meter software maintenance charges.
3. Technical support service charges from the Company's smart meter supplier.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring all customers, from residential to C&I and generation and transmission interconnections, have reliable and accurate billing information. This operation maintains the health of the electric smart meters, and enables customers to participate in programs, such as the time-of-use program, and the ability to have more granular information about their energy consumption through a Web portal and to realize the benefits of smart meter technology.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 26, column (l), the Company is projecting to spend $9,690,000 in the test year.

Q. How were these spending amounts determined?

A. The charges underlying these spending amounts are fixed by a contract that establishes the charging rates through 2032. These rates are based on the number of active electric smart

meters the Company has installed at customer locations, and meter inventory levels required to meet new business and meter failure requirements throughout the year. As these charges are fixed, the spending forecast is based on the projected number of meters, and is adjusted annually based on projections for new business, regulatory requirements, or other large projects. Spending in this program has remained relatively flat for the last five years, and that trend should continue in coming years.

Grid Management – Distribution

Q. What work activities are carried out in the Grid Management – Distribution O&M sub-program?

A. Grid Management is responsible for providing statewide 24/7 monitoring and control of the LVD and HVD systems. This includes providing statewide dispatch of electric field resources to respond to electric service interruptions, electrical hazards, and other calls related to electric services reported by customers. Grid Management coordinates and administers planned work supporting electric reliability projects, maintenance work, and customer-related work on the HVD and LVD systems. Grid Management is also responsible for the coordination of major electric service restoration efforts associated with storms and other natural disasters. Lastly, Grid Management is responsible for operating grid automation devices and using advanced applications to improve system reliability, reduce outage duration, ensure power quality within MPSC regulations, and reduce energy waste. O&M expenses in this program are for the salaries and expenses of operating and support function employees at the control and dispatch centers that the Company operates.

Q. How does this work benefit customers?

A. This work benefits customers by allowing for the timely restoration of electric service, securing and clearing of electrical hazards impacting public safety, isolating failed equipment and performing partial service restorations, and remotely operating field devices to reduce outages and mitigate emergency conditions impacting the system or the public.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 27, column (l), the Company is projecting to spend $4,164,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on employee salaries for the necessary headcount to fill the operating and support roles in the program, representing an amount of $3,605,000. Additionally, expenses associated with each department in the program, as well as annual software maintenance fees, communication maintenance costs and fees, and substation communication equipment demand maintenance costs, are in the amount of $559,000.

Grid Automation

Q. What work activities are carried out in the Grid Automation O&M sub-program?

A. The Grid Automation team consists of personnel primarily responsible for planning and developing the Company's Grid Automation programs and projects, as described in the testimony of Company witness McPhail.

Q. How does this work benefit customers?

A. Grid Automation deploys automation tools to improve reliability, enhance situational awareness, and support faster service restoration. These capabilities allow the Company

to detect and isolate faults more quickly, minimize the number of customers affected by an outage, and restore power remotely when conditions allow. Grid Automation also provides improved visibility into real-time system performance, enabling operators to make more informed decisions that strengthen both reliability and operational efficiency.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 28, column (l), the Company is projecting to spend $2,313,000 in the test year.

E. <u>Performance Innovation & Strategy</u>

Q. Please describe the O&M work related to the Performance Innovation & Strategy Program.

A. The Performance Innovation & Strategy program supports the Electric Distribution organization by providing the strategic direction, workforce capabilities, tools, and digital innovation necessary to operate a safe, reliable, and efficient electric system. The program is composed of four coordinated sub-programs—Strategy, Training, Tools, and Performance & Innovation—each of which plays a distinct role in ensuring the organization is equipped to meet current and future operational needs.

Q. What are the sub-programs in the Performance Innovation & Strategy O&M Expense Program?

A. These sub-programs, as shown in Exhibit A-94 (EMD-10), lines 30 through 33, are:

1. Training;
2. Tools;
3. Strategy; and
4. Performance & Innovation.

Training

Q. What work activities are carried out in the Training O&M sub-program?

A. The Training sub-program covers expenses whenever groups in the Electric Operations organization, excluding the underground workforce group, conduct official training courses, generally at the Company's Marshall Training Center or another designated training location, typically with a course instructor. These training courses include skills-based training using both classroom time and instructor-led fieldwork at the training location for Electric Operations employees, including Electric Lines, Substation Operators and Maintenance, Electric Field Lab, and Electric Meter Operations. For example, a training course for lineworkers to move from the Step 1 to the Step 2 classification involves about three weeks of training at the Marshall Training Center. The Company also uses on-the-job training in the field for many purposes, and that is not part of the Training O&M sub-program; those costs are instead charged to the actual job in the field being completed.

The Training O&M sub-program also includes expenses for operating the Company's Apprenticeship Program, including paychecks earned by apprentices while they are at the training center. Aside from the Apprenticeship Program, union labor associated with additional hours of training, such as continuing education and required annual training courses, are also paid out of the Training O&M sub-program. Full-time and temporary union instructors who administer the training are also funded in this sub-program.

Q. How does this work benefit customers?

A. This work benefits customers by ensuring the Company has enough employees with the required training to have the skills to complete field work, and ensuring employees are properly trained in safety procedures.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 31, column (l), the Company is projecting to spend $13,200,000 in the test year.

Q. How were these spending amounts determined?

A. The expenses for this sub-program were determined based on the number of employees, apprentices, and external candidates, multiplied by the expected hours training they will receive each year.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by the Company's projected increased headcount in its field operations workforce, which in turn increases the training expenses that must be incurred. Company witness Babale describes this in more detail.

Tools

Q. What work activities are carried out in the Tools O&M sub-program?

A. The Tools O&M sub-program includes the cost of procuring tools valued under $1,000, including the U.S. Department of Labor's Occupational Safety and Health Administration ("OSHA") safety devices, testing equipment, and utility-specific industry tools, particularly fire-retardant clothing.

This equipment is required to maintain, inspect, and re-calibrate the equipment on Company trucks for use in the field. The Tools O&M sub-program also includes expenses related to tool repairs.

Q. How does this work benefit customers?

A. This work enables a safer, faster response to outages, safe and efficient installation of new services, and more productive completion of projects with less waste and lower unit costs. In general, adequate tools are required to complete field work to improve reliability and restore service. Some tools, such as fire-retardant clothing and other personal protective equipment are essential for employee safety and are required by OSHA regulations.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-94 (EMD-10), line 32, column (l), the Company is projecting to spend $1,751,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is determined based on the size of the field operations workforce, which in turn determines how many tools, including fire-retardant clothing and personal protective equipment, the Company needs.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in this sub-program is being driven by the Company's projected increase in its field operations workforce to support the Reliability Roadmap.

Electric Distribution Strategy

Q. Please describe the O&M expenses related to the Electric Distribution Strategy Program.

A. The Electric Distribution Strategy Program expenses include salaries for the Distribution Strategy team, who is responsible for leading engagement activities for Distribution with stakeholders throughout the state, developing the long-term strategy for the organization, and helping to manage the organization's capital budget.

Q. What is the Company's projected test year spending for Electric Distribution Strategy?

A. As shown in Exhibit A-94 (EMD-10), line 30, projected spending in this sub-program is $702,000 in the test year. This is in line with recent levels. Note that spending in Electric Distribution Strategy may fluctuate from year to year based on hiring of consultants to conduct projects such as the EJ Regression analysis that was first ordered in Case No. U-21389.

Performance & Innovation

Q. Please describe the O&M expenses related to the Performance & Innovation Program.

A. The Performance & Innovation O&M Program includes the expenses necessary to support the Company's standards development and continuous improvement activities. This includes funding for the Standards Management Group, which maintains and updates the Company's electric distribution construction and maintenance standards, and the Work Methods & Joint Committee Group, which develops and refines field work methods, evaluates new tools and practices, and collaborates with labor representatives through the

joint committee process. These expenses ensure field work is performed safely, consistently, and efficiently across the distribution system.

Q. What is the Company's projected test year spending for Performance & Innovation?

A. As shown in Exhibit A-94 (EMD-10), line 33, projected spending in this sub-program is $1,784,000 in the test year.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending in this sub-program is being driven by the Company's projected increase in its work methods & joint committee workforce to support the Reliability Roadmap.

F. Management & Chargebacks

Q. Please describe the O&M work related to the Management & Chargebacks Program.

A. The Management & Chargebacks Program includes the administrative, oversight, and internal cost-allocation activities that support day-to-day electric operations. This work covers functions such as coordinating operational processes, managing internal billing and chargeback activities, processing damage claims, and supporting meter-related operational needs. These activities ensure that operational costs are accurately assigned, financial transactions are properly recorded, and internal programs have the administrative structure needed to operate efficiently. Overall, this program provides the foundational management, financial controls, and support services necessary for effective execution of the Company's electric distribution operations.

Q. What is the Company's projected test year spending for Management & Chargebacks?

A. As shown in Exhibit A-94 (EMD-10), line 35, projected spending in this sub-program is $5,564,000 in the test year, which is lower in comparison to recent levels.

G. Work Management and Customer Delivery

Q. Please describe the Work Management and Customer Delivery Program as shown on Exhibit A-90 (EMD-6), line 7.

A. The Work Management and Customer Delivery O&M sub-program work activities performed are as follows:

- Work Management and Customer Delivery includes functions for Distribution Planning, Scheduling, Close-Out and Admin, and CEM. Planning ensures the operating plan adheres to the Company's business plan for Electric Operations field work.
- Scheduling ensures field crews have enough work, ready-work, and the right work and resources to complete the work plan.
- The Close Out and Admin functions ensure technical documentation is accurate and complete, and the costs of the work settle appropriately to the work orders.
- The CEM team is focused on meeting customer needs by providing a single point of contact for customer-requested service and meter installations, and alterations. CEM is responsible for ensuring all new customer service requests and customer-requested alterations on the Company's distribution system are coordinated from initiation through completion to meet customer expectations.

Q. Please describe the O&M expenses related to the Work Management and Customer Delivery Program.

A. The Company is projecting Work Management and Customer Delivery O&M expenses of $1,775,000 in the projected test year, as shown in Exhibit A-94 (EMD-10), line 36, column (l). This spending level is primarily based on projected headcount in the organization.

IX. AMI METRICS

Q. Please explain the requirement to include value-focused AMI metrics and elements in electric rate case filings.

A. The Commission's March 1, 2024 Order in Case No. U-21389 stated:

> As set forth in this order, and in lieu of the continued provision of future advanced metering infrastructure business case updates, Consumers Energy Company and the Commission Staff shall meet as soon as reasonably possible after the date of this order to coordinate on appropriate value-focused advanced metering infrastructure metrics and elements for the company to include in its future rate case filings.

Q. Please explain how the Company is complying with this requirement.

A. The Company met with Staff on March 25, 2024, April 11, 2024, and April 23, 2024, to coordinate appropriate value-focused AMI metrics and elements for the Company to include in its future rate case filings. During those meetings, Staff provided feedback into proposed AMI metrics and elements. The value-focused AMI metrics and elements that have currently resulted from the coordination between Staff and the Company are included in Exhibit A-100 (EMD-16).

X. SUMMARY

Q. Please summarize your testimony.

A. In this testimony, I have provided an overview of the Company's electric distribution system, including detailed information on the system's recent reliability, and the Company's plan to improve that reliability over the coming years.

I have explained how the Company developed its Reliability Roadmap, and how the plan provided in the Reliability Roadmap will increase investment in the distribution system to improve reliability for customers in the face of increasingly severe weather.

The Company's distribution investments will adhere to the four objectives defined in the Reliability Roadmap, going beyond reliability to ensure safety and security for employees and the public; ensure an equitable grid; and keep costs affordable for customers. By following this strategy, the Company has developed the detailed capital and O&M spending plans outlined in this testimony and the direct testimony of Company witnesses Partlan, LaFrance, and McPhail.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am a Principal Rate Analyst for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Please state your educational background.

A. I graduated from Michigan State University with a Bachelor of Business Administration with a major in finance.

Q. What are your responsibilities in your current position?

A. In my role as a Principal Rate Analyst, I am responsible for the development of Capital and Operations & Maintenance ("O&M") plan targets that align with rate case results.

Q. Please describe your prior work experience.

A. I have held my current position since April 2018. Prior to this role, I held various accounting analyst roles within the finance organization, including in the General Accounting and Property Accounting Departments. In these roles, I have been responsible for property records, financial results, accounting entries, analysis, and reporting, including Federal Energy Regulatory Commission ("FERC") and Michigan Public Service Commission ("MPSC" or the "Commission") report filings.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Case Nos. U-21224, U-21308, U-21389, U-21490, U-21585, U-21806, U-21870, and U-21981 which include the Company's most recent natural gas and electric general rate cases.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony is in five parts. In Part 1, I address the test year O&M expense for Corporate Services, insurance expense, uncollectible expense, injuries and damages expense, and digitization of Company records project costs. In Part 2, I will address the test year capital expenditures for Corporate Services. In Part 3, I include a summary of Corporate Memberships. In Part 4, I will address technology projects that support the Corporate Services functions. In Part 5, I address the Company's requested accounting approval for the use of regulatory assets or regulatory liabilities.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-104 (MJF-1)	Summary of Projected Electric & Common O&M Expense for the Year 2025 and the 12 Months Ending April 30, 2028;
Exhibit A-105 (MJF-2)	Electric Projected Corporate Services O&M Expense for the Year 2025, and the 12 Months Ending April 30, 2028;
Exhibit A-106 (MJF-3)	Electric Actual and Projected Property, Liability and Other Insurance O&M Expense for the Years 2021 through 2025 and the 12 Months Ending April 30, 2028;
Exhibit A-107 (MJF-4)	Electric Uncollectible Accounts Expense for the Years 2021 through 2025, and the 12 Months Ending April 30, 2028;
Exhibit A-108 (MJF-5)	Electric Injuries & Damages Expense for the Years 2021 through 2025 and the 12 Months Ending April 30, 2028; and

Exhibit A-109 (MJF-6)		Electric Corporate Membership Dues for the Year 2025
Exhibit A-12 (MJF-7)	Schedule B-5.3	Electric Corporate Services Capital Expenditures for the Years 2025 through the 12 Months Ending April 30, 2028.

Q. Were these exhibits prepared by you or at your direction?

A. Yes, they were.

PART 1 – ELECTRIC CORPORATE SERVICES O&M EXPENSE

Q. Please describe Exhibit A-104 (MJF-1).

A. Exhibit A-104 (MJF-1) summarizes the Company's total 2025, and the 12 months ending April 30, 2028 electric O&M expenses for Corporate Services, insurance expense, uncollectible accounts, injuries and damages, and digitization of Company records project costs. Column (a) of this exhibit provides the O&M expense category, column (b) provides the 2025 actual O&M, column (c) provides the projected test year 12 months ending April 30, 2028 O&M. Exhibit A-104 (MJF-1), page 2, illustrates how historical O&M costs are adjusted to reflect inflation, and additional cost increases or decreases. Column (a) of this exhibit provides the O&M expense category, column (b) provides the source exhibit, column (c) presents the historical O&M expense, column (d) shows the expected increase in these costs based solely on projected inflation rates, column (e) captures cost increases or decreases beyond inflation, column (f) represents the total projected test year O&M expense, calculated as the sum of columns (c), (d), and (e). These expense categories are discussed below.

Corporate Services O&M Expense

Q. What areas are included within the Corporate Services O&M expense category, as shown in Exhibit A-104 (MJF-1), line 1?

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These areas include Sustainability and External Affairs; Legal, Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and Development; Finance and Shared Services; General Activities; and Administration and other costs.

Q. Please provide a brief overview of the various areas within the Corporate Services area.

A. The areas within Corporate Services include:

- Sustainability & External Affairs – This area acts as a conduit between the Company and its employees, customers, and external stakeholders. The group manages storm communications, promotes safety messaging, advances clean energy programs for the benefit of customers via public media relations and inquiries, advertising, corporate news releases, social media management, and trade association dues and memberships. This area also manages corporate strategy, strategic projects, foundation operations, and community programs. It is responsible for employee diversity and inclusion and strategic talent sourcing;

- Legal, Ethics, Regulatory, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, Risk Management, Quality Lean Department, and it is responsible for determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs. The Corporate Compliance Department is responsible for maintaining a healthy ethical culture, including training on the Company's Code of Conduct and Guide to Ethical Business Behavior, misconduct investigations, and oversight for 40 regulatory compliance areas. The Corporate Secretary Department is responsible for sound corporate governance, including board meetings, shareholder meetings, minutes, shareholder services, and Board of Directors costs. The Securities Law Group is responsible for ensuring full and fair disclosure to investors through compliance with public-company regulatory and legal requirements.

Corporate Information Governance is responsible for creating and sustaining a company culture where all employees treat information as an asset, including adherence to the information governance principles: accountability, transparency, integrity, protection, compliance, availability, retention, and disposition. The Risk Management area provides services for corporate insurance programs, surety bonds, and review of commodity and credit risks associated with natural gas, electric fuel, and power purchases. Gas and electric insurance programs include the management of property and casualty insurance paid to cover the business including property damage, director and officer's liability insurance, public liability insurance, workers' compensation insurance, fiduciary liability insurance, and fidelity insurance. The Legal Organization is responsible for legal matters involving litigation, credit and collections, environmental, contracts, and other transactions, real property, labor and benefits, business development, and regulatory matters at the state and federal levels. The Quality Lean department is responsible for the Company's quality management system. This department establishes and maintains standards, processes, procedures, and policies that ensure both Company and regulatory requirements are consistently met. Key responsibilities include developing and implementing standards, processes, procedures, and policies, supporting overall business efficiency by reducing waste and errors, and enhancing customer satisfaction by addressing potential or identified non-conformances.

- P&C and Learning and Development – This area is responsible for creating and executing on the employee experience for all co-workers at Consumers Energy. An engaging employee experience is critical for hiring and retaining the necessary talent to benefit customers and the State of Michigan. The employee experience is comprised of all interactions and services that employees experience during their time with the Company, including recruiting, hiring, training and development, succession planning, compensation, payroll, performance management, workforce relations, employee engagement, and benefits administration. Also included is compliance assurance, which addresses legal and regulatory requirements such as Equal Employment Opportunity, Americans with Disabilities Act, and Family and Medical Leave Act;

- Finance and Shared Services – This area provides the preparation of utility strategic financial plans, budgets, forecasts, and specialized financial studies. This area also includes the preparation and control of accounting records, including financial statements and reports, and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, fixed assets, and financial and regulatory reporting. The internal audit functions and the internal control functions are conducted in this area. The corporate tax function includes all aspects of compliance with federal, state, and local income, sales and use, property, franchise, and excise taxes, book accounting for taxes, tax planning of transactions, tax research, the analysis of tax legislation and regulations, the management and negotiation of

tax audits, and tax litigation. Treasury includes all aspects of Company financing and cash management, negotiation of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing, and investing. Corporate Safety includes operations safety, managing safety data, developing a safety strategy, and safety culture. In addition, investor relations, rating agency, and investor support are included in the Finance and Shared Services area.

- General Activities – These costs are an aggregation of expenses and credits that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include capitalized credits to O&M, billing credits for administrative and general ("A&G") labor, expenses, and outside services as part of a full-cost loading adder, and senior management time and expenses; and

- Administrative and Other – These costs are primarily for Edison Electric Institute dues, environmental minimum liability accruals, and intervenor funding.

Q. How are the Corporate Services expenses allocated between the Company's electric and gas businesses?

A. Allocations are developed based upon the type of cost. For example, billing costs are allocated based on customer counts for the electric and gas business, P&C are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities allocated based on capital and O&M spending levels or special studies.

Q. What is the Three Factor Allocation Method?

A. The Three Factor Allocation Method uses the average of operating revenue, labor, property, plant, and investments to allocate costs between the electric and natural gas businesses.

Q. Explain how the Adjusted Corporate Services O&M expense was calculated.

A. Exhibit A-105 (MJF-2), line 12, provides the Company's electric portion of total Corporate Services expenses, before exclusions. The 2025 actual O&M expenses were obtained from the Company's records. Specific line-item changes are included as increases or decreases as appropriate to reflect exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate Services O&M expense. The total of items disallowed by Commission order related to corporate giving, communications, dues, donations, and lobbying payments were removed on Exhibit A-105 (MJF-2), line 18. Total adjusted Corporate Services expense is found on Exhibit A-105 (MJF-2), line 19.

Q. What is the projected rate of inflation?

A. The assumed rate of inflation is based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. The CPI is 2.9% for 2026, 2.5% for 2027, and 2.2% for 2028. Consumers Energy uses these inflation rates to project Corporate Services O&M. Company witness Hannah L. Patton supports the inflation rates used.

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Plan ("EICP") included in the 2025 actuals or projected Corporate Services O&M expense?

A. No. Further details regarding restricted stock and EICP expenses are covered under the direct testimony of Company witness Amy M. Conrad.

Electric Insurance Expense

Q. Please describe Exhibit A-106 (MJF-3).

A. Exhibit A-106 (MJF-3) summarizes the Company's total 2021 through 2025 actual electric insurance expense and projected insurance expense for the 12 months ending April 30, 2028.

Q. What expense level is the Company proposing to recover in this case as part of the test year?

A. The Company projects the insurance expense for the test year at $15,265,839 as shown on Exhibit A-106 (MJF-3), line 6, column (h).

Q. How did the Company determine the insurance expense included in the test year?

A. The projected insurance premiums expense is based on the historical compound annual growth rate for 2021 through 2025 actual insurance premiums as shown on Exhibit A-106 (MJF-3), column (g). The historical compound annual growth rate is then applied to the 2025 actual insurance premiums to calculate the projected test year insurance premiums as shown on Exhibit A-106 (MJF-3), line 4, column (h). Given the year-to-year variability in refund distributions, the projected amount used the five-year average actual distributions from 2021 to 2025 as shown on Exhibit A-106 (MJF-3), line 5, column (h). The projected insurance O&M for the test year, as shown on Exhibit A-106 (MJF-3), line 6, Column (h), is derived by offsetting premiums with refund distributions.

Q. Why did the Company use the compound annual growth rate instead of the annual inflation rate to project insurance premiums for the test year?

A. In recent years, the Company's electric insurance premiums have increased at a rate exceeding the annual inflation rates. In a previous electric rate case, Case No. U-21585,

the year 2023 was used as the historical test year, with projections extending through the 12 months ending February 28, 2026. The actual electric insurance premiums for 2023 were $18.1 million, which, when adjusted for inflation, resulted in a projected premium expense of $19.0 million for the test year. However, the actual electric insurance expense for 2025 was $19.3 million, indicating an under-recovery of approximately $0.3 million compared to the inflation-adjusted projection. This supports the need to use the compound annual growth rate to project electric insurance O&M.

Electric Uncollectible Expense

Q. How did the Company determine the uncollectible accounts expense included in the test year?

A. The Company projects the uncollectible accounts expense for the test year at $21,560,811 as shown on Exhibit A-107 (MJF-4), page 1, line 1, column (c). The projected test year uncollectible accounts expense is based on a three-year historical average Bad Debt Loss Ratio ("BDLR") of cash basis uncollectible accounts expense to electric service revenue for the years 2023 through 2025, as shown on Exhibit A-107 (MJF-4), page 2. This ratio is applied to the test year electric service revenue, plus surcharge revenue, to arrive at the sub-total of uncollectible accounts expense on Exhibit A-107 (MJF-4), page 2, line 9, column (e).

Q. Does the estimate of uncollectible accounts expense consider changing fuel and power costs, their impact on customer bills, and the corresponding impact on uncollectible accounts expense?

A. Yes. By using the test year revenues multiplied by the three-year average BDLR, the latest fuel and power cost projections are taken into account.

Q. Does this method provide a reasonable estimate of uncollectible expense?

A. Yes. The Company continuously strives to reduce uncollectible accounts expenses. However, year-over-year, uncollectible accounts expense can be impacted by many factors. The economy, the effectiveness of collection practices, funding of low-income assistance programs, extreme weather fluctuations, or any number of other factors that could impact a customer's ability to pay. As a result, the Company is proposing a three-year average BDLR from 2023 through 2025 in this rate case filing. This method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expenses.

Electric Injuries and Damages Expense

Q. Please describe Exhibit A-108 (MJF-5).

A. Exhibit A-108 (MJF-5) summarizes the Company's total 2021 through 2025 actual electric injuries and damages expense and projected injuries and damages expenses for the 12 months ending April 30, 2028.

Q. Please describe the costs related to injuries and damages.

A. Electric injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops; restoration of driveways, lawns, and fences; and accidents and lawsuits (up to a $3,000,000 insurance deductible per occurrence). Further, workers' compensation costs are included in injuries and damages along with associated internal legal costs.

Q. What expense level is the Company proposing to recover in this case as part of the test year?

A. The Company is proposing that a total of $5,702,657 be included for the test year as shown on Exhibit A-108 (MJF-5), line 4, column (g).

Q. How was this amount determined?

A. Injuries and damages expense is comprised of three components: electric injuries and damages, internal legal costs, and workers' compensation costs. Exhibit A-108 (MJF-5), line 1, reflects the electric property and liability damages. Line 2 represents the amount of internal legal costs that are charged to injuries and damages. Line 3 represents the level of workers' compensation costs for each year. The test year amounts for each of the three components of total injuries and damages' expense are based on a five-year average of actual expense for the years 2021 through 2025.

Digitization of Company Records Costs

Q. Please describe the digitization of Company records.

A. The digitization of Company records involves transforming approximately 41,000 boxes of physical documents into electronic formats using scanning technology and specialized software, enabling them to be easily searched, shared, and accessed remotely. The initiative includes document shredding to ensure proper disposal of physical materials.

Q. What type of Company records will be included in the digitization of Company records?

A. Company records to be digitized include work orders, equipment details, personnel files, real estate deeds, easements, contracts, environmental documentation, and financial reports.

Q. What expense level is the Company proposing to recover in this case as part of the test year?

A. The Company is proposing that a total of $1,260,000 be included for the test year as shown on Exhibit A-104 (MJF-1), page 1, line 5, column (c).

Q. How did the Company arrive at the projected expense for the test year?

A. The digitization of Company records is expected to incur annual costs of $2 million, with a total estimated expense of $10 million over a five-year period. The allocation of the projected gas and electric expenses was performed using the Three Factor Allocation Method, as discussed earlier in my testimony.

Q. What are the benefits of digitizing company records?

A. There are numerous benefits to digitizing Company records in addition to fulfilling regulatory compliance.

- **Increased Accessibility and Responsiveness** – The Company will be able to access necessary records efficiently, eliminating delays associated with locating, scanning, and electronically transmitting physical copies. Digitization eliminates some of the wasted time spent waiting for information, allowing employees to serve customers faster and be more efficient. Text recognition and other functionalities can make searches or retrieval of information possible in ways that are nearly impossible with paper records. Centralized data can provide Artificial intelligence ("AI") tools with increased data to utilize, resulting in better analytics and improved forecasting abilities. Digitizing records enables the Company to focus on value added tasks instead of manual processes and labor through paper-based work. In the event of a disaster or recovery effort, the Company will have quicker and easier access to essential information, allowing focus on restoring operations rather than locating critical records. Digitized records enable faster responses to regulatory and other inquiries, while also ensuring more thorough, efficient, and reliable preservation of records when required.

- **Improved Safety and Security** - Paper records are at a higher risk of destruction, loss, or theft than a digital version which can be backed up and have more extensive security measures in place. These security measures provide customers and the Company with greater protection of privacy and confidentiality of personal

information. Employees in high-risk roles will have greater and faster access to critical information, supporting safer operations through more informed decision-making. Paper and other physical media have a limited lifespan, making records susceptible to damage or becoming unreadable over time. In contrast, digital records can be preserved indefinitely, transferred easily, and maintain their quality without the risk of deterioration. The process helps the Company meet regulatory compliance of the records lifecycle.

- **Cost Savings and Improved Service for Customers –** The Company can utilize data that is not readily available in paper form to make more informed decisions and reduce the amount of time a customer waits for a response or completion of work. This results in improved decision making that is customer focused. The current records retention site can be repurposed for something of greater benefit to customers instead of a space to indefinitely store paper records. Digitized records enhance the efficiency of customer-facing processes such as scheduling, dispatch, and field operations, ultimately leading to better overall customer experience.

PART 2 – ELECTRIC CORPORATE SERVICES CAPITAL EXPENDITURE

Q. Please describe Exhibit A-12 (MJF-7), Schedule B-5.3.

A. Exhibit A-12 (MJF-7), Schedule B-5.3, summarizes the Company's total 2025 through the 12 months ending April 30, 2028 electric capital expenditures for Corporate Services. Column (a) of this exhibit provides the program description; column (b) provides the 2025 actual capital; column (c) provides the projected 2026 capital; column (d) provides the projected 4 months ending April 30, 2027 capital; column (e) provides the projected 16 months ending April 30, 2027 capital; and column (f) provides the projected test year 12 months ending April 30, 2028. These categories include costs to equip and support Learning & Development and the Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

Q. Please explain how the projected Corporate Services Capital expenditures were calculated.

A. The 2025 actual capital expenditures were obtained from the Company's records, and projected inflation rates were applied as described in my direct testimony above and as shown on Exhibit A-12 (MJF-7), Schedule B-5.3, page 2.

PART 3 – CORPORATE MEMBERSHIPS

Q. Has the Company filed supporting documentation detailing its corporate membership dues expense and the corresponding customer benefits?

A. Yes, as the Commission directed on pages 330-331 of its March 27, 2026 Order in Case No. U-21870, the Company has prepared an exhibit detailing its corporate membership dues expense and the corresponding customer benefits. Specifically, Exhibit A-109 (MJF-6) provides documentation of the Company's 2025 corporate membership dues and describes the customer benefits. Column (a) shows the name of the organization; Column (b) provides a description of the organization; Column (c) summarizes the benefits of the memberships; Column (d) reports the total membership costs; Column (e) reports the cost of the membership included for recovery in this rate case.

Q. Do the membership costs sought for recovery in this rate case include any lobbying-related activities or expenses?

A. No. Memberships, or portions of memberships, related to lobbying activities are excluded from recovery. Workpaper WP-HLP-18 supported by Company witness Patton shows the total disallowed Dues, Donations & Lobby expenses for 2025. The amount of disallowed lobbying activity costs (approximately $219,000) is included in column (g), lines 1 through 10 of the workpaper.

Q. Apart from lobbying-related expenses, does the Company request recovery of all remaining corporate membership costs?

A. No. Pursuant to the MPSC order in Case No. U-15245, the Company disallows recovery of one-third of non-lobbying costs. Workpaper WP-HLP-18 Column (e), lines 12 through 14 shows the amount of disallowed Corporate Membership Dues (approximately $382,000).

Q. What benefits do customers receive from the Company's corporate memberships?

A. In addition to the benefits identified in Exhibit A-109 (MJF-6), customers benefit from a cost-effective means for the Company to access benchmarking opportunities, best practices, research, and professional networking. Benchmarking enables the Company to compare its performance with other utilities and identify opportunities to enhance customer service. Access to research and best practices offers insights into industry-leading approaches that inform Company initiatives and help the Company better serve customers. Through networking opportunities, the Company strengthens communication with peer utilities and the ability to share knowledge to better serve customers.

PART 4 – CORPORATE TECHNOLOGY PROJECTS

Q. Is the Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Stacy H. Baker includes, in her direct testimony and exhibits, technology projects that are critically important in enabling the Company's Corporate Services functions to support the Electric business in a safe, effective, efficient, and compliant manner. Exhibit A-19 (SHB-3) contains the breakdown of Company spend for each project. These projects are described below:

- The **Enterprise Risk Management** project requires $40,671 in capital ($32,537 in ROM adjusted capital) and $13,542 in O&M in the test year.

  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 data.

  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 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 ERT, RO, senior management, and the BoDs 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; and (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.

PART 5 – ACCOUNTING REQUESTS

Deferral of State Income Taxes Requests

Q. Company witness Brian J. VanBlarcum requests authorization to defer certain Michigan income tax expense. Please summarize the accounting request.

A. The Company requests Commission authorization to defer for future recovery of Michigan income tax expense if the Company is unsuccessful in defending the state apportionment position described in Mr. VanBlarcum's testimony.

Illinois State tax recovery

Q. Company witness VanBlarcum requests authorization for the Company to recover Illinois State income tax expense in future rate cases. Please summarize the accounting request.

A. As outlined in Mr. VanBlarcum's testimony, the Company requests Commission approval to recover Illinois state income tax expense from customers in future rate proceedings. The expenses are associated with the Company's Midcontinent Independent System Operator, Inc.-apportioned sales in Illinois.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Alex M. Gast, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. What is your position with Consumers Energy Company ("Consumers Energy" or the "Company")?

A. I am the Director of Regulatory Strategy & Research in the Customer Experience & Growth department ("CX&G").

Q. Please state your educational background and work experience.

A. In 2011, I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration, with a major in accounting. In 2013, I graduated from Spring Arbor University with a Master of Arts degree in Business Administration. I am also a Certified Public Accountant registered in the state of Michigan.

From 2012 to 2014, I was employed by Plante & Moran as a Staff Auditor. My responsibilities included the planning and execution of financial statement audits, reviews, and consulting engagements for a variety of non-profit, healthcare, and manufacturing clients.

In 2014, I joined Consumers Energy as a Business Support Advisor in the Distribution, Operations, Engineering, and Transmission department. My responsibilities included managing financial budgets, forecasts, and long-term financial plans for natural gas and electric programs. In 2015, I joined the Energy Resources department as a Financial Analyst where I worked on business plans and performance metrics and was promoted to the lead of that team in 2016. In 2018, I joined the Pricing section of the Rates and Regulation department, and my responsibilities included cost of service studies, rate

design, research and development of additional services, analyses for Senior Management, and customer-specific rate analyses. In 2023, I joined the Customer Experience department as a Principal Rate Analyst and was promoted to Manager of Customer Regulatory Strategy and then Director of Regulatory Strategy & Research in 2025. I am responsible for regulatory strategy and filings related to the Company's clean energy plan, including Demand Response ("DR"), Energy Waste Reduction ("EWR"), and Electrification.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I filed testimony on behalf of the Company in the following proceedings before the Commission:

Case No. U-20365	2018 EWR Reconciliation;
Case No. U-20372	2020-2023 EWR Plan;
Case No. U-20650	General Gas Rate Case;
Case No. U-20702	2019 EWR Reconciliation;
Case No. U-20865	2020 EWR Reconciliation;
Case No. U-20875	2022-2025 EWR Plan;
Case No. U-20893	Investment Recovery Mechanism Reconciliation;
Case No. U-21148	General Gas Rate Case;
Case No. U-21389	General Electric Rate Case;
Case No. U-21647	2023 DR Reconciliation;
Case No. U-21870	General Electric Rate Case;
Case No. U-21906	2024 DR Reconciliation; and
Case No. U-21981	General Gas Rate Case.

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my direct testimony is to describe the CX&G organization and how the work performed within this organization benefits the Company's residential and business electric customers. As part of my direct testimony, I will address the operating and maintenance ("O&M") expenses and capital investments associated with executing this work in the test year ending April 2028.

My direct testimony will also describe the Company's DR program, associated costs, and proposed updates. As part of my direct testimony, I will address: (i) the DR O&M expenses and capital investments in the test year ending April 2028. Included in this filing is the reconciliation for calendar year 2025 of the DR Program per the December 18, 2025 Order in Case No. U-21637.

Finally, my direct testimony will discuss the Transportation Electrification Plan ("TEP") that will continue to improve customer experience and benefits without any budgetary increase from prior MPSC approvals.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (AMG-1)	Schedule B-5.7	Actual and Projected Capital Expenditures - Customer Experience & Growth;
Exhibit A-110 (AMG-2)		Summary of Actual & Projected O&M Expenses – Customer Experience, Customer Operations: Customer Interactions;
Exhibit A-12 (AMG-3)	Schedule B-5.8	Actual and Projected Capital Expenditures – Demand Response;
Exhibit A-111 (AMG-4)		Summary of Actual & Projected O&M Expenses – Demand Response;

Exhibit A-112 (AMG-5)		2025 Annual Demand Response Investments by Portfolio and Program;
Exhibit A-113 (AMG-6)		2025 Customer Enrollments;
Exhibit A-114 (AMG-7)		DR Revenue Requirement Calculation for the 2025 Reconciliation Period;
Exhibit A-115 (AMG-8)		Calculation of DR Levelized Costs;
Exhibit A-116 (AMG-9)		Calculation of DR Financial Incentive;
Exhibit A-12 (AMG-10)	Schedule B-5.9	Transportation Electrification Plan Capital Expenditures;
Exhibit A-117 (AMG-11)		Summary of Actual & Projected O&M Expenses – Electric Transportation Deferred Asset Costs; and
Exhibit A-118 (AMG-12)		Transportation Electrification Plan Cost Benefit Analysis.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

I. Customer Experience and Growth
  A. Customer Interactions
    1. Digital Customer Operations
      a. Energy Assistance Enhancements and Maintenance Annual Updates
      b. Customer Product Family Enhancements
    2. Customer Contact Center
    3. Business Center Care
    4. Credit and Assistance
    5. Analytics and Outreach
  B. Billing and Payment
    1. Customer Billing
    2. Customer Payment Programs
  C. Regression Analysis on Equity of Shutoffs

II. Demand Response
- A. Cost Details
- B. Surcharge and Regulatory Framework
- C. Residential DR
- D. Business DR
- E. DR Pilot
- F. DR Reconciliation
  1. Projected and Actual Costs
  2. Residential DR
     a. Projected and Actual Residential Costs
     b. Residential MW Achievements
     c. Proposed Residential Program Changes
  3. Business DR
  4. Utilization of DR Resources
  5. Revenue Requirement Calculation
  6. Levelized Cost Calculations
  7. Performance Incentive
  8. DR Program Cost Deferred Accounting
     a. DR Program Incentive Accounting

III. Electric Vehicles
- A. TEP Program

I. CUSTOMER EXPERIENCE AND GROWTH

Q. Please describe Exhibit A-12 (AMG-1), Schedule B-5.7.

A. Exhibit A-12 (AMG-1), Schedule B-5.7, details the capital expenditures related to direct work within the CX&G organization, which totaled $126,000 in the historical year, $1.0 million projected in the bridge period, and $510,000 projected in the test year. This reflects a financial forecast based on the work plan and designated development activities within Analytics and Outreach, Customer Billing, and Credit and Assistance areas.

Please note that this testimony also discusses the Customer Information Technology ("IT") project benefits related to the spend sponsored by IT Company witness Stacy H. Baker.

Q. Please describe Exhibit A-110 (AMG-2).

A. Exhibit A-110 (AMG-2) details the O&M expenses related to work within the CX&G organization, which total approximately $40.8 million for the test year ending April 30, 2028.

Q. Please describe Exhibit A-110 (AMG-2) page 4.

A. Exhibit A-110 (AMG-2), page 4, is a hypothetical illustration of the CX&G projected O&M expenses based on inflation. This page is for illustrative purposes only and is not intended to represent how the Company has developed its projected CX&G O&M. Column (b) shows the actual historical O&M expense for the year ending December 31, 2025. Column (c) shows the historical amount, to which an inflation rate was applied. Column (d), scope/cost increases net of productivity gains, has also been applied to the historical amount. Column (d) shows the total projected O&M for the test year through April 30, 2028.

Q. Please provide a summary of the CX&G O&M expenses and capital investments projected in the test year.

A. CX&G is projecting capital expenses of $845,000 in the bridge period 2026, $170,000 in the bridge period 2027, and $510,000 in the test year, as mentioned above, as well as approximately $40.8 million in O&M expense for the test year ending April 30, 2028. This amount comprises $28.1 million of O&M expenses for Customer Interactions, and $12.6 million for Billing and Payment. The CX&G O&M expenses are presented in detail on Exhibit A-110 (AMG-2). The historical and projected capital costs for these programs are included in Exhibit A-12 (AMG-1), Schedule B-5.7.

DEPARTMENT	CAPITAL	O&M
Customer Interactions	$510,000	$28.14 million
Billing & Payment		$12.64 million
Total	**$510,000**	**$40.78 million**

The Company is also projecting $184,566 in O&M for customer investment to support the CX&G IT infrastructure. All IT-related costs discussed in this testimony are in the IT capital and O&M budget and discussed by Company witness Baker.

Q. Has the Company undertaken any initiatives to lower costs related to CX&G O&M expense?

A. Yes. Incorporated into the CX&G O&M projection is $8.1 million of net recurring customer benefit to the electric business due to changes to the payment process. This is the result of implementation of a fee-based model for payments submitted through vendor payment channels to ensure the cost distribution for payments is fairly represented between residential customers and non-residential customers who choose to pay with a high-cost payment method or fee-based channels versus those who use fee-free payment methods**.** Combined with gas O&M, total savings equal $15.8 million.

Q. Please describe CX&G.

A. The CX&G organization strives to optimize a customer's positive experience when interacting with the Company. It has two major components -- Customer Interactions and Billing & Payment. Customer Interactions ensures that customers are equipped to connect with the Company in their preferred channel (phone, Interactive Voice Response ("IVR"), website, mobile app, or digital correspondence—such as text messages). Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings (e.g., inability to pay

arrangements, pay by phone/website, payment alerts, choose your own bill due date) for individual customers.

These two core functions are fundamental to accomplishing the Company's customer experience goals. The Company relies on its array of customer experience offerings to ensure that customers are satisfied when interacting with Consumers Energy and are therefore positively inclined to enroll in its available programs.

Q. The inclusion of a Growth team within Customer Experience team is new since the Company filed its last electric rate case. Please explain why this team was added, their responsibilities, and any associated cost.

A. The CX&G Growth team was assembled to focus on intentional, planned load growth within the Company's service areas. The team consists of employees who had previously been part of an external outreach team or economic development team, providing benefits for both new and existing customers. Associated costs are the result of internal shifting of cost centers. Related costs are included in the Customer O&M calculations within the Business Customer Care ("BCC") organization.

Q. Is the Company's IT witness sponsoring any CX&G-related projects?

A. Yes. Company witness Baker is sponsoring $184,566 in O&M costs for Energy Assistance Enhancements and Maintenance Annual Updates. The customer benefit of this project will be discussed later in my testimony. Please see Company witness Baker's testimony for implementation and cost information.

The IT department is a critical CX&G partner and CX&G relies on IT expertise to help develop and implement necessary digital solutions. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity

risks. IT also supports analytic platforms and solutions that provide deeper insight into customer needs, enabling CX&G to establish appropriate targets for metrics, products, and customer programs, necessary to allow CX&G to select the most cost-effective and beneficial solutions for customers. Together, CX&G and IT ensure customers receive secure, reliable, up-to-date, and positive experiences across all channels of interaction with the Company. Continued investment in technology requires additional ongoing funding to initiate, support, and maintain vital platforms.

A. Customer Interactions

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for the ownership and execution of the channels of customer interactions as identified above. This work includes the following areas of focus: the Digital Customer Operations ("DCO"), Customer Contact Center, BCC, Credit and Assistance, and Analytics and Outreach. Each area of focus is aligned to the larger Customer goals of: (i) providing customers the opportunity to interact with Consumers Energy via their channel of choice; (ii) facilitating program enrollment and product selection to meet customer energy needs; (iii) providing support and guidance to the Company's business customers; (iv) supporting the Company's most vulnerable customers with information and enrollment in assistance programs; and (v) achieving the Company's clean energy goals. To effectively perform in these areas, the Company is projecting $28.1 million of O&M expenses and $510,000 in capital for the test year ending April 30, 2028 as shown on Exhibit A-110 (AMG-2) and Exhibit A-12 (AMG-1), Schedule B-5.7.

1. Digital Customer Operations

Q. Please provide an overview of DCO.

A. DCO is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including its website and mobile application. The team leads the design, development, and launch of the Company's technologies, as well as ensuring that the technologies are responsive to customer needs and requested changes. Steady innovation is a testament to the group's value to both the Company and the Customer.

The team collects customer survey feedback every month, which drives the team's priorities in four simultaneous work cycles: (1) small, agile digital changes using available tools; (2) managing the design, development, and launch of monthly releases to add new features or modify user flows; (3) leading major technology projects that add new or modify existing functionality to better serve customers; and (4) executing the implementation of programs online to help accrue energy savings and clean energy opportunities for customers.

To continue this work, the Company is projecting approximately $2.75 million of O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents an increase in O&M expenses of $1.8 million from the $930,000 expenditure in 2025.

The primary driver of this is an increase in labor costs in the test year.

- $1.4 million labor increase
  - $0.6 million net new O&M support in Experience Design
  - $0.4 million increase for new Customer Digital labor
  - $0.3 million Residential Product Utility

- $0.4 million non-labor expense increase
  - $0.3 million net new O&M support in Experience Design
  - $0.1 million increase for new Customer Digital non-labor

Q. What types of transactions do customers complete online?

A. The most common transactions customers completed in 2025 using the Company's website and mobile app were (1) checking the billing status of their account, (2) making payments, (3) reporting outages or viewing the status of an outage, (4) checking energy usage information, and (5) investigating additional service information—such as auto-pay, eBill enrollment, budget billing, and information on products and services. The Consumers Energy website also serves as the principal vehicle to enable customers to sign up for clean energy program rebates, enroll in energy saving programs, and save money with energy-efficient products.

COMMON TRANSACTIONS	WEBSITE	APP
Check billing status	13.9 million	6.4 million
Make payments	18.1 million	5.0 million
Outage related	10 million	1.7 million
Energy usage information	780 thousand	1.4 million
Additional services	2.2 million	Not available on the app

Q. Please explain why the Company is continuing to invest in multiple digital methods to allow customers to complete transactions or find information in their channel of choice.

A. The Company continues to invest in multiple digital methods for customer interaction to meet evolving customer needs, habits, and expectations, as customer behavior continues to

shift toward more integrated and sophisticated digital services. These investments support and ensure channel parity, ensuring customers can complete the same transactions regardless of whether they choose digital or assisted channels.

Expanding and maintaining the Company's digital channels enables customers to conduct a wide range of activities through a smartphone or computer at times that are more convenient than the limited call center service hours. This shift enables customers to self-serve while reducing reliance on higher-cost assisted service. In 2025, customers paid $4.7 million daily in bills through the web and mobile app. Together, both channels are on track to see $1.7 billion in payments yearly. Online transactions cost approximately $0.11 compared to $10.18 per live agent call (utilizing internal contact center resources), making digital channels a significantly more cost-effective alternative to expanding the call center service hours.

The Company's digital channels are customer-facing, critical systems that require ongoing operational support to ensure they function reliably when and how customers expect. It is important to note that, like most peer institutions (e.g., DTE, UPPCO, Indiana Michigan Power/AEP), for which this has become the customer expectation, the Company continues to support several channels in response to customer needs and choices for communicating and completing transactions, including the Company's IVR System, desktop/mobile website, and the mobile app. For example, DTE supports customer interaction through its main website (DTE Energy Home | DTE Energy), a chat feature on its website, and a mobile app. Similarly, UPPCO (Home - UPPCO) and Indiana Michigan Power/AEP (Indiana Michigan Power) offer customer interactions through their main websites, as well as interactive phone portals. Indiana Michigan Power/AEP additionally

offers a mobile apps. Maintaining these channels reflects customer expectations and supports the diverse needs of customers across generations, locations, and socio-economic circumstances.

a. Energy Assistance Enhancements and Maintenance Annual Updates

Q. Please describe the Energy Assistance Enhancements and Maintenance Annual Updates project.

A. The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as the Consumers Affordable Resource for Energy ("CARE") project, will implement changes to the software that supports programs offering 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 include criteria from the Department of Health and Human Services ("DHHS") and the MPSC to prioritize the list of changes.

Q. Why is this project beneficial for Customers?

A. Each grant year, DHHS and MPSC stipulate the criteria required for customers' enrollment in the CARE Program, how the Company and support 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 change significantly each year and consequently, the Energy Assistance Enhancement and Maintenance Annual Updates application requires related modifications to meet the new requirements.

The project will deliver value by enabling the Company to support Low Income Energy Assistance Fund ("LIEAF") funding across internal, partner and customer-facing systems. Specifically, the project will: (1) Complete required modifications to internal SAP application and Agency Portal to receive LIEAF funding, which is used to apply bill credits and provide arrears forgiveness for eligible customers; (2) Improve the data within the assistance agencies portal, making it easier to assist customers in need of LIEAF funding; and (3) Complete necessary modifications to customer facing platforms to support the delivery of LIEAF-related assistance.

Q. Please provide a scope for the project.

A. The project scope includes updating the enrollment and status process; facilitating flat monthly bills; improving reporting; updating the arrears forgiveness plan; satisfying additional regulatory requirements for the required annual grant rule changes; updating CARE dunning process; and updating the assistance portal functionality to enhance Agency Self-Service.

Q. What is the risk if the project is not funded for implementation?

A. Failure to meet applicable regulatory requirements could result in the loss of state LIEAF funding that supports low-income customers in paying their energy bills, thereby increasing the risk of service shutoff for nonpayment. Because MEAP is also funded through LIEAF, the Company must implement program changes as directed by the MPSC Assistance Division MEAP team. To continue delivering these customer benefits, Consumers Energy requires funding to make the necessary modifications and upgrades to remain compliant with state requirements. Absent such compliance, benefits available to low-income customers could be jeopardized.

Q. Were additional options considered?

A. Yes. Transferring the administration of Energy Assistance Programs to a third-party organization was considered but ultimately rejected as it would remove the Company's ownership and visibility into the health of the program while increasing administrative costs.

Q. Is this project related to the low middle income ("LMI") Customer Enhancement Project?

A. No. These are two separate projects.

b. <u>Customer Product Family Enhancements</u>[1]

Q. Please describe how Customer Product Family Enhancements are identified and implemented.

A. CX&G Customer Product Family Enhancements are technology improvements which benefit customers and are implemented in response to the launch of a channel, customer tool, project completion, and/or direct customer feedback. Depending on the need identified, enhancement dollars could be utilized to support the enhancement of any customer supporting feature and/or capability, often as emerging requests. These items are small-scope items with a reduced budget and fewer resource requirements in comparison to larger capital investments. Having the flexibility to implement Customer Product Family Enhancements enables the Company to meet the customers' needs. Examples of enhancements include improving overall functionality of the channel or tool, analytics on platform usage, addressing issues identified internally or via customer feedback, adding relevant or customer-driven capability, and performance monitoring.

[1] For 2021 and 2022, the actual project name was Enhancements-CX&G-Capital and starting in 2023, the project is named Product Family Enhancements-Customer-Capital.

Q. How do Customer Product Family Enhancements benefit the Company's customers?

A. Enhancements assist the Company in providing a better, more optimized customer experience for customers through improved understanding of how they use the channels or tools, which features are important to their experience, and how the channels or tools are performing.

Q. Is the Company again requesting approval for funding for Web Chat AI on the website?

A. Yes. Customers have demonstrated a clear preference for digital self-serve through website and mobile app, as evidenced by significant growth in these channels over the past 5 years. Internal Company research indicates that providing a web chat capability helps customers remain in self-service channels as customers generally expect to be able to resolve issues on a 24/7 basis. An AI-driven chat bot supports these expectations by enabling customers to receive assistance at any time without requiring the level of ongoing labor associated with a staffed live chat option. As a result, AI chat functionality represents an effective way to extend self-service capabilities while avoiding the incremental costs of additional staff support.

Q. What is the expected customer benefit of a Web Chat AI bot?

A. First and foremost, there is an opportunity to improve customer satisfaction within the digital channel through the introduction of a chat bot. The Company's research and survey data shows that when customers can complete their reason for visit, their satisfaction improves by almost 100 points (from -24 to 76) when the customer is able to complete their task through the website. Consequently, the Company knows that approximately 22% of customers generally state that they were unable to complete their task online, often driving

them to have to call in in order to get resolution with their issue. The team estimates that once the bot is in with the first four major releases, the chatbot could result in a decrease of up to 400,000 calls annually.

Q. What have been some early indicators of success?

A. The Minimum Viable Product ("MVP") version of the chatbot launched to customers on January 29, 2026. Since then, the chatbot has handled 24,026 customer conversations. The MVP version of the chatbot is a simple question and answer search feature, enabling customers to easily find answers to their questions on the website. A high-level analysis was conducted of customers that interacted with the chatbot. Conversations were analyzed and high-level call data was extrapolated to determine the volume of calls avoided since the launch of the chatbot. Since the launch, it is estimated that almost 21,000 calls have been reduced from the live customer contact center. The chatbot has a 61% average customer sentiment, as measured based on a simply thumbs up/thumbs down on the response, and has an 86% containment rate.

Q. What plans does the Company have to expand the chat bot's capability through the remainder of 2026?

A. Two additional releases are planned for 2026. The next release in the summer will add authenticated functionality into the bot allowing logged in customers to get specific account balance and payment information about their personal account through the bot. The third release planned for Q3 will have self-service high bill analysis built in, allowing customers to query the bot to understand why their bill changed, what drove the changes, and how they can mitigate for future. Additional functionality would be released in 2027

allowing for other self-service options for example, reporting outages, signing up for alerts, among other things.

Q. How has the Company responded to the Commission's concerns with this project in past electric and gas rate cases?

A. The Company has taken steps to follow the Commission's prior guidance regarding both (i) the importance of customer-specific data to demonstrate the benefits of Web Chat AI and (ii) the Commission's interest in seeing continued progress on the Company's broader website redesign. Please refer to the Commission's March 27, 2026 order in Case No. U-21870 at page 206 and the Commission's September 30, 2026 order in Case No. U-21806 at page 137. Consistent with that guidance, the Company is providing customer-specific performance information above, including observed reductions in contact center calls since the January 29, 2026 MVP launch. While the Company continues to evaluate and advance broader website modernization initiatives (as discussed in the testimony of Company witness Baker), based on the above metrics, Web Chat AI is an appropriate and prudent investment independent of the pace or sequencing of a full website redesign.

Web Chat AI is a modern, least-cost method to deliver necessary customer communications and handle common customer requests at scale. It functions as a digital front door—providing customers with timely, consistent information and guiding them to the appropriate self-service transaction or assisted channel when needed. More specifically, Web Chat AI is a targeted, measurable enhancement to the Company's existing digital channel that (1) improves customers' ability to complete common tasks through self-service on a 24/7 basis, (2) helps manage peak contact volumes and reduces reliance on higher-cost assisted channels, and (3) improves accessibility for customers who

prefer not to call or who have barriers to calling. In addition, as the tool expands from a basic Q&A feature to authenticated capabilities, it can serve as a scalable digital intake and triage function that complements other digital improvements and supports required customer communications.

A broader website redesign would not negate the need for investment in Web Chat AI because the chatbot is a distinct customer-service capability that must be designed, trained, integrated, tested, and supported regardless of the website's visual layout or navigation. A redesign may change where and how customers access help, but customers will continue to seek timely answers and guided self-service assistance, and Web Chat AI provides that function in a scalable, least-cost manner. Deferring Web Chat AI until completion of a full website redesign would delay customer and operational benefits without avoiding the core costs of developing the chatbot capability. For these reasons, the Company requests approval of Web Chat AI funding in this proceeding.=

2. Customer Contact Center

Q. Please provide an overview of the Customer Contact Center.

A. The Customer Contact Center is responsible for staffing and operating the Company's call centers, which serve all residential and small business customer calls. In 2025, call center representatives answered over 2.5 million customer calls. Likewise, the IVR system addressed 4.6 million calls in 2025.

To continue this work, the Company is projecting $13.9 million of O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents a decrease in O&M expenses of $188,000 from the $14.1 million expended in 2025. The decrease can be attributed to non-labor expense decreases in the test year.

- $0.24 million overall labor increase due to virtual call center labor allocation change
- ($0.42 million) non-labor expense ***decrease***

3. Business Customer Care ("BCC")

Q. Please provide an overview of BCC.

A. BCC directly impacts the Company's C&I customers, and includes the Business Center, which assists the Company's larger business customers with support such as phone agents and account management. BCC's main goal is to deliver exceptional customer experience, while identifying opportunities that provide the Customer with added energy value and opportunities. Overall, BCC serves approximately 100,000 customers, equating to 200,000 contract accounts.

To continue the work in this area, the Company is projecting $3.7 million in O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents an increase in O&M expenses of $1.5 million from the $2.1 million expended in 2025, with the increase attributed to higher labor and contactor costs in this area.

- $1.2 million labor increase
  - $0.35 million Growth labor increase (full headcount vs partial 2025)
  - $0.56 million Energy Solutions Manager labor new utility O&M allocation
  - $0.1 million Sales Enablement labor new utility O&M allocation
  - $0.2 million Business Center labor increase (full headcount + merits)
- $0.3 million non-labor expenses increase
  - $0.15 million Sales Enablement expense new utility O&M allocation
  - $0.1 million Growth non-labor expense increase

Q. The Company's Growth team is included in the BCC spend. Please provide an overview of Growth.

A. The Growth team was formed through the strategic consolidation and formalization of existing Business Customer Care staff whose work had organically expanded in scope, complexity, and coordination requirements beyond what the prior organizational structure could efficiently support. Consolidating these functions into a dedicated team reflects sound operational management.

These roles were created to address a longstanding gap in the Company's ability to proactively engage business customers at critical decision points involving expansion, relocation, and major capital investments. The Growth team currently has a pipeline of potential customers, totaling 9 GW, across dozens of new developments.

Prior to the Growth team's formation, this work was handled inconsistently and reactively across multiple internal organizations, limiting effectiveness and accountability. Moreover, under the legacy structure, individual team members of the BCC organization independently managed projects from initial inquiry through final execution, a generalist model that was adequate when business customer requests were largely transactional and self-contained. Today, the nature of requests has changed. Customer needs present complex, multi-phase infrastructure questions that require deep coordination among feasibility analysis, infrastructure contracting, rate design, and operational planning. Specifically, the new structure aligns coworkers to specific areas of expertise: project scoping, customer programming, energy solution development, contracting, and strategic liaison functions with operational partners: transmission, distribution, and planning departments. This specialization deepens

the Company's institutional knowledge, reduces internal project risk, and accelerates the timeline from customer inquiry to service delivery; outcomes that will reduce cost in future years and risk for the entire customer base. The Growth team's specialized structure matches that complexity and centralizes the work and responsibilities to improve efficiency for customers while reducing duplicative work across multiple organizations.

The Growth team's work is foundational to the Company's obligation to serve. The Growth team's customer-facing and infrastructure-planning work reduces long-term system costs, supports load stability, and growth; benefits that accrue to all customers through maintaining system utilization and spreading fixed costs across a stable customer base, not merely to individual project participants.

4. Credit and Assistance

Q. Please provide an overview of Credit and Assistance.

A. The Credit and Assistance area consists of: (1) Theft Investigations; (2) Revenue Operations; and (3) Energy Assistance, which collectively manage the Company's collections cycle and support its most vulnerable customers by connecting them with Company-sponsored payment plans and public assistance funding to help customers pay their bills.

The Theft Investigation Team provides the critical service of identifying and ending energy theft in the Company's service territory - important both for maintaining the safety and integrity of the Company's system and minimizing all customers' costs. In 2025, the team identified 2,090 confirmed cases of theft and billed for $1,914,028.08 in unauthorized use and investigation costs–a decrease of 92 cases but an increase of about $329,400 billed over the previous year.

Revenue Operations addresses past due customer accounts or accounts involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers and ending with visiting their premises to disconnect service. This group also manages contracts with outside collection agencies to recover payments from customers with outstanding balances. 2025 Agency recoveries (Uncollectible Account collections) totaled $10.9 million from previously written off balances. 2025 Theft investigations resulted in $1.9 million in recoveries (billed cases), as a result of unauthorized use and investigation costs. Recovery of these payments directly offsets the uncollectible expense discussed in the testimony of Company witness Matthew J. Foster.

The Energy Assistance team is responsible for administering the Company's CARE Program, which supports low-income customers who may be struggling to pay their monthly energy bills and helps to provide customers with either a one-time bill assistance payment or on-going support via enrollment in an Affordable Payment Plan ("APP"). By coordinating with other organizations in fiscal year 2025, this team obtained $9 million of APP-specific assistance and an additional $5.5 million in as-needed assistance for its customers requested through the MEAP.[2] In addition to MEAP assistance, customers received $26 million in State Emergency Relief ("SER") payments and $11 million in Home Heating Credit assistance. Note these figures include assistance for both electric and gas customers.

To continue the work in this area, the Company is projecting $2.9 million in O&M expenses and $510,000 in capital for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), the O&M request represents an increase of $150,000 in O&M

[2] The MEAP offers customers options for reduced monthly bills while gradually paying down any arrears brought into the program or a one-time payment toward their bill.

expenses from the $2.8 million expended in 2025, due to increased labor for merits and micro design headcount changes.

Q. Please provide additional details about the $510,000 in capital spending in this area.

A. The capital request is to support the LMI Customer Support Enhancement, which in this phase of work is focused on two outcomes: 1) inclusion of the Single Enrollment Flow into the logged in experience to improve efficacy of program recommendations and meet customers where they are and 2) Shut Off Protection Plan digital redesign. It is important the Company continue progress built upon successful implementation to date so that the customers who need energy assistance actually engage and receive helpful benefits and savings.

For historical context, the Company's stated core functions for the project have been and continue to be four-fold:

- streamlining enrollment—providing clear, step-by-step guidance through enrollment processes, and ensuring the enrollment information is mobile friendly;
- creating proactive communications—using data to proactively reach out to LMI customers with education and options;
- integrating new programs—and redesigning if necessary to meet the needs of the LMI customers; and
- continuous improvement and feedback—incorporating feedback about what works and what doesn't.

Q. What has been the performance of the LMI Customer Support Enhancement project to date?

A. Since its implementation, the LMI Customer Support Enhancement has provided solutions that make interactions with the Company and its LMI-related resources more accessible, supportive, and efficient, while facilitating enrollment into assistance programs to reduce

energy burden for LMI customers. This project has facilitated collecting targeted, personalized data to provide customers with earlier communication and opportunities to enroll in payment assistance and income-qualified programs including budget plan, payment arrangements, shut-off protection, home energy audits, helping neighbors, DR, renewable energy, and more.

For example, the Single Enrollment Flow ("SEF"), which was the first step in this customer-focused improvement, has shown positive metrics since implementation.

- Since launch, 335,000 customers have engaged with the tool, and 119,000 have self-identified as LMI, confirming strong visibility and interest from the intended user base.
- Over 108,000 enrollments have been completed in the flow and nearly 20% of customers enrolled in more than one offering, highlighting the tool's effectiveness in simplifying access to multiple programs.
- This streamlined experience reduces enrollment barriers and helps customers navigate offerings like EWR, DR, Payment Plans, and Energy Assistance offerings.
- 85% of surveyed customers rated the tool "extremely or very easy to use."
- Direct customer comments reinforce this ease and appreciation:
  - *"Very easy to do and understand thanks. I am a senior citizen."*
  - *"This was a wonderful surprise after dealing with shutoff notices. It was easy to use and seemed designed to be user friendly."*
  - *"I just can't believe how easy and helpful this process was... if I hear anyone talking about having trouble paying their bill, I will be telling them about this."*

Q. Please explain the first outcome to include Single Enrollment Flow in the logged in experience.

A. Presently, when a customer logs into their account, key indicators such as payment status and payment history will inform targeted recommendations. For example, customers who

are past due may be directed to payment assistance or payment arrangement options, while customers with repeated late payments may be guided to programs such as Select Your Due Date. These recommendations connect customers to relevant support at the moment a potential need is identified.

By embedding SEF into the logged in experience, the Company streamlines access to programs, increases awareness of available assistance, and reduces the effort required for customers to enroll. This proactive, personalized approach helps ensure that customers who need support are guided to appropriate options earlier, improving customer outcomes while reducing downstream collections activity.

This next phase advances affordability, equity, and customer understanding by shifting access to assistance from a reactive model to one that anticipates customer needs and delivers clear, timely guidance.

Q. Please explain the second outcome, redesign of the Shut Off Protection Plan.

A. The second outcome will support a digital redesign of the Shut-Off Protection Plan ("SPP"). SPP provides 18 months of shut-off protection and is available to customers with a household income at or below 400% of the federal income eligibility guidelines. The plan requires an initial down payment of 10% of the total bill (20% if one prior default) and spreads your annual energy costs and arrears into equal monthly payments. Additionally, all seniors (65 and older) qualify for the 18 months of shut-off protection. The digital redesign of SPP will include re-architecting systems and workflows to introduce new capabilities for identifying customers in bill crisis, dynamically applying appropriate protections, and enabling structured transitions to sustainable affordability solutions once the immediate crisis is resolved.

This work represents an extension of the Company's recent investments in simplified and personalized enrollment capabilities by redesigning how shut-off protection is delivered within the digital platform. The redesign introduces new capabilities that improve timeliness, consistency, and effectiveness through real-time customer identification, automated eligibility assessment, and proactive program matching. These changes enable the system to guide customers toward the most appropriate assistance and payment solutions based on payment status, history, and eligibility, while embedding targeted, system-driven recommendations directly within the authenticated digital experience at the moment of need.

Customers who engage with SPP are experiencing a bill crisis that could result in service disconnection absent timely intervention. In these circumstances, assistance programs, such as SER, the CARE program, and MEAP affordable payment, are most effective when applied rapidly and in alignment with individual customer needs. Currently, identification of eligible customers and routing to appropriate programs relies heavily on manual processes and customer-initiated actions, limiting scalability and consistency of outcomes. The redesign aims to automate these manual functions.

Overall, this investment seeks to transform SPP from where it is today to being more system-driven. While the initiative does not expand eligibility or program benefits specifically, it creates new digital capabilities that change how those programs are able to be delivered, extend the long-term utility of the platform, and generate measurable operational and customer value.

Q. How will investment in this project benefit all Consumers Energy customers?

A. While this project's primary focus is to support LMI households, it will benefit all customers by continuing to deliver and improving upon the five noted benefits: (1) Enhancing energy equity: by broadening access to bill assistance and utility programming this solution gets the Company one step closer to ensuring everyone has equal access to basic utilities; (2) addressing the risk of unpaid bills and service disconnections isn't just compassionate and the right thing to do, it's also cost-effective; preventing service cuts reduces administrative costs and lost revenue which will positively impact all customers: (3) building trust with LMI customers fosters a sense of loyalty and increases their willingness to engage proactively, not just in times of crisis; (4) reducing the bill and energy burden on low-income families enhances their overall quality of life and financial stability; and finally, engaging LMI households not only in bill assistance programs but also in clean energy solutions is crucial for environmental sustainability aligning with the Company's Clean Energy Plan and the state's MI Healthy Climate Plan. Together, these benefits not only support vulnerable customers but also create a more cost-effective and sustainable future for everyone.

5. Analytics and Outreach

Q. Please describe Analytics and Outreach.

A. The Analytics and Outreach team includes several multi-faceted teams that support the overall customer analytics, strategy, experience design for utility products, and research activities used to improve the overall customer experience. This team:

- supports the overall enterprise and partners with teams across the Company to include the voice of customers in business decisions, strategies, and processes;

- helps to identify new technological needs for the company to better serve customers and for customers to more easily self-serve;
- supports building business cases for new work or customer service tools;
- builds data visualizations and automated processes; and
- works with other parts of the Company to improve customer outcomes within the billing & payment, outage, move in/move out, and field experiences.

To continue this work, the Company is projecting approximately $4.9 million in O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents an increase in O&M expenses of $2.3 million from the $2.6 million expended in 2025. The primary driver of this is an increase in labor-related costs in the test year.

- $1.15M labor increase
  - $0.65M net new O&M support in Brand, Marketing, Voice of Customer ("VoC"), User Acceptance Testing
  - $0.33M in labor shift for new CX&G leadership structure
  - $0.13M variance from historical for full Strategy headcount (multiple vacancies in 2025)
- $1M contracted services increase
  - $0.3M VoC Customer Experience Enterprise Feedback Management Solution
  - $0.2M VoC Kubra & Veregy
  - $0.5M for IT allocation

The Customer Strategy & Transformation team was established at the end of 2025. The need for this team was driven by the requirement to centralize functions that span the totality of the Customer space and to lead the Company's customer strategy, regulatory engagement, digital transformation efforts, and deployment of lean practices, all with a focus on improving customer outcomes and aligning internal operations around a shared

goal. This area includes the reallocation of team members from across the organization to support Digital Transformation (Digital Product Management – Product Family), Customer Strategy, and Customer Regulatory Strategy and Research. Two new leadership roles were brought on specifically as experts in their respective fields to lead transformation in how the Company plans, roadmaps, and implements customer strategies and technologies. In addition to setting vision and direction, the team connects efforts across functions, working closely with gas and electric operations, regulatory, digital, product, and other business units to ensure the customer agenda is fully integrated and actionable across the enterprise.

Increases for new IT allocation reflect higher annual costs charged by the Company's IT organization and are not driven by discretionary spending decisions within Analytics & Outreach. These costs are allocated based on usage and include data platforms, analytics tools, cybersecurity, reporting infrastructure, and digital engagement systems that are foundational to the CX&G organization. Year-over-year increases in these allocations are expected and reflect rising enterprise IT costs rather than reduced operational efficiency.

New spend for Voice of the Customer CX Enterprise Feedback Management Solution reflects the cost of stabilizing and coordinating existing customer feedback activities and does not represent a new or discretionary initiative. Customer feedback is already collected today but is dispersed across multiple tools and processes. The proposed investment consolidates these existing activities into a single, centrally governed framework to support consistent collection and management of customer

feedback across the Company, which supports more timely and consistent identification of customer issues.

Increases for labor & contractor services in the Brand Strategy team are due to headcount changes and increased costs associated with contractor staffing support, creative production of brand assets, and social media platform services. The addition of two Brand and Creative FTE's reflect a measurable increase in required workload and scope, driven by new and expanded customer-facing obligations. Specifically, the test year includes a significant increase in regulated customer communications, expanded bill messaging and notifications, and increased program assistance communications tied to affordability and customer protection initiatives. These requirements necessitate additional capacity for content development, regulatory review coordination, production, and versioning across bill inserts, direct mail, digital channels, and customer service enablement materials.

During the test year, the Brand and Creative team also assumes expanded responsibility for centralized, inhouse production of customer communications work to accommodate increased volume and demand previously supported through external agencies. This shift provides internal capacity to meet increased volume and demand without reliance on incremental external agency or third-party resources.

The additional FTEs provide dedicated internal capacity to manage increased creative volume, maintain consistency and accuracy across communication channels, and support time-sensitive regulatory and customer-driven communications. This staffing approach enables the Company to scale production and manage costs more predictably by reducing dependence on higher-cost external agency services for incremental work.

B. Billing and Payment

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for leveraging customer feedback to ensure payment processes are simple and consistent, monthly energy bills are accurate and easy to understand, and customers receive their bills in a timely fashion. The work in this department is divided between Customer Billing and Customer Payment programs. The Company is projecting $12.6 million in O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents an increase in O&M expenses of approximately $1.8 million from the $10.9 million expended in 2025. This increase is mainly due to increases in postage, materials, and labor costs.

1. Customer Billing

Q. Please provide an overview of Customer Billing.

A. Customer Billing manages the exceptions process--a quality control process designed to (1) review unusual bills (both digital and paper), and/or (2) bill for unique programs before they are sent to customers. The review may involve contacting customers to gather additional information or to inform them of a potential billing issue. Bills may be corrected through the billing adjustment process, or meters may be reread as part of the validation process. Rigorous efforts to ensure every customer bill is accurate results in the Customer Billing team continually optimizing its processes and technology to aid in the billing exception review. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $11.2 million of O&M expenses for the test year ending April 30, 2028. As shown on Exhibit A-110 (AMG-2), this represents an increase of $1.8 million from the $9.4 million expended in 2025, due to United States Postal Services ("USPS") postage increases in 2024 and 2025.

- $1.3 million increase in postage mail & material costs for customer paper bills and notices due to annual USPS postage increases of ~ 7% per year
- $0.2 million labor increase for merits
- $0.3 million in labor shift for new Billing & Rev Ops Leadership (from multiple C&I areas)

Q. Please explain the costs within Customer Billing.

A. The cost for stationery, forms, and postage related to the Company's billing and dunning communication processes is included in Customer Billing. The Company expects to mail 20 million paper bills, and approximately 2 million dunning notices in 2026.

To mitigate cost increases, the Company has taken action to increase customer enrollment in electronic billing, or eBill. Consumers Energy has successfully increased eBill participation from <27% in 2017 to 50% as of the second quarter of 2025. This growth has offset postage costs by over $2.5 million annually by reducing the number of pieces mailed.

However, cost per piece of postage has steadily increased over the past three years, a cost expected to continue to increase due to nearly annual US Postal Service postage increases. As noted previously, postage costs are forecast at a 7.8% increase year over year through 2030. These increases offset the savings the Company has realized from growing its eBill enrollment, without which increases in the cost for postage would have contributed to the cost of customer billing over time.

2. Customer Payment Programs

Q. Please describe the CX&G Customer Payment Programs group.

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with its customers, with approximately 34 million payments made annually. The Company's Customer Payment Program group focuses on removing payment difficulties,

providing payment options that customers expect, and ensuring all customers have the same easy payment experience regardless of how they choose to pay their bill. This has resulted in a significant reduction of payment-related calls and complaints and improvement in customer experience. The Company continues to make it a priority to accommodate customer preferences with a variety of options to meet current customer expectations and to maintain a single set of customer-friendly payment rules that apply across all payment options.

Q. Please describe the costs associated with the Customer Payment Programs.

A. The Company is projecting $1.5 million in the test year O&M expenses shown on Exhibit A-110 (AMG-2). This represents a $64,000 decrease from the $1.5 million expended in 2024. The decrease is due to ending certain payment services.

- Net decrease of $64,000 due to ending payment services (Vantiv & Card Connect). Other costs largely remain flat overall.

Q. What are the anticipated payment processing fee costs for the test year?

A. Within the $1.5 million of Customer Payment Programs test year O&M expense, the Company is projecting $130,254 in payment processing fees O&M expenses for the test year. Additional payment-related fees include bank lock box fees in the amount of $550,800, approximately $464,800 in Direct Payment Office ("DPO")-related payment fees, and $305,815 for Payment Management (formerly the Billing & Payment Program Support team).

Q. Are there additional changes to the way the Company collects payment processing fees?

A. As discussed above, the Company has implemented a policy change, resulting in a fee-based model for payments submitted through vendor payment channels.

Q. Does the Company anticipate any revenues generated by assessing payment card service fees to customers continuing to pay with a credit/debit card?

A. No, the Company does not anticipate or forecast any revenue being generated from payment processing fees.

Q. What are the merchant fees that customers pay for use of credit/debit cards?

A. All customers using credit/debit cards pay a flat fee per transaction. Residential customers pay $2.99 per transaction and C&I customers pay $9.99 per transaction, regardless of rate schedule. These fees are paid directly to the third-party payment processor, Paymentus.

Q. Please provide an overview of DPOs.

A. Consumers Energy currently has six DPOs around the state of Michigan, all located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. These offices provide a community resource that can connect customers with billing options and assistance opportunities.

Q. Does the Company offer other in-person payment options in addition to the remaining DPOs?

A. Yes. The Company has maintained its relationship with an authorized pay agent, which accepts payments at stations such as Wal-Mart, Kroger, and other associated store fronts. These pay stations serve as de facto DPOs. This provides customers with the continuity and convenience of being able to pay their bill without having to locate a DPO. Customers are charged a fee to pay their bill in these locations, which covers the costs of the processing fee the Company is charged to have this option.

Q. Does the Company itself collect the payment fee?

A. It does not. The authorized pay agent implements and collects the fee from the customer utilizing their services.

Q. What is the payment fee?

A. The payment fee is $1.50 per transaction, per the agreement between the vendor and the Company.

C. Regression Analysis on Equity of Shutoffs

Q. Please discuss the Company's analysis related to the equity of shutoffs of residential customers.

A. The Commission's final Order in Case No. U-21389 directed the Company to include an analysis of residential shutoffs in the regression analysis that the Company was already conducting into equity issues in distribution reliability. This analysis of residential shutoffs was conducted by the Company as part of the broader regression analysis that Company witness Emily M. Duke describes in her direct testimony and sponsors as Exhibit A-97 (EMD-13). The findings of this analysis were presented in Case Nos. U-21585 and U-21870.

Q. Has the Company conducted further regression analyses?

A. Yes. The Commission's order in Case No. U-21389 stated that regression analyses should be included as a regular matter in subsequent rate cases. The order in Case No. U-21870 confirmed this and offered minor refinements on variables to be included. Accordingly, Consumers Energy conducted another analysis and is sponsored by Company witness Duke as Exhibit A-97 (EMD-13).

Q. What were the findings from this continued analysis?

A. The results of the current analysis are consistent with those of the previous analysis. The analysis shows no evidence that census tracts with the worst reliability consistently experience statistically significant, higher disconnection rates than other census tracts.

When all other variables and factors are held constant, increasing electric energy burden (as a percentage of income) in a census tract is statistically significant and associated with increasing disconnection rate. Energy burden was found to have the greatest correlation with disconnection rate among all predictors included in the analysis. The statistically significant positive correlation between Percentage Minority Population and disconnection rate that was previously observed persists even when energy burden is controlled for but is smaller than the correlation between energy burden and disconnection rate.

II. DEMAND RESPONSE

Q. Please describe Exhibit A-12 (AMG-3), Schedule B-5.8.

A. Exhibit A-12 (AMG-3), Schedule B-5.8, details the capital expenditures related to DR in the historical year, bridge period, and projected in the test year.

Q. Please describe Exhibit A-111 (AMG-4), page 1.

A. Exhibit A-111 (AMG-4), page 1, details the O&M expenses related to DR in the historical year and projected in the test year.

Q. Please describe Exhibit A-111 (AMG-4), page 2.

A. Exhibit A-111 (AMG-4), page 2, includes projections for DR O&M based on inflation. This page is not intended to represent how the Company has developed its projected DR O&M. Column (b) shows the historical O&M expense. Column (c) shows the historical

amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a hypothetical inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases for each respective period. Because the Company does not develop the projected DR O&M using inflation it is necessary to include column (i), other adjustments. Column (i) is simply the difference between the Company's actual projected O&M and what the O&M would have been if the Company had used inflation to project DR O&M. Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). The expenses supported here are based upon the expenses necessary to meet the needs of DR program planned in the test year and are not based on applying an inflation rate to the historical O&M expenses.

Q. Please describe Exhibit A-112 (AMG-5), page 1 and 2.

A. Exhibit A-112 (AMG-5), page 1 provides 2025 DR Program planned and actual costs and revenue requirements and page 2 identifies Residential and Business investments by program.

Q. Please describe Exhibit A-113 (AMG-6).

A. Exhibit A-113 (AMG-6) provides the 2025 DR Program enrollments by total portfolio.

Q. Please explain the DR programs offered by the Company.

A. The Company offers a DR portfolio comprising of both residential and business DR programs. The portfolio consists of three residential programs: Device Cycling, Dynamic Peak Pricing ("DPP"), Residential Smart Thermostat; and two business programs: Commercial and Industrial ("C&I") Contractual DR, and C&I Rate options.

- Residential Device Cycling involves installing direct load control switches on high energy use equipment at customer homes. These switches are capable of

receiving DR event signals that turn off connected loads for a specified amount of time during events. At the end of 2025, the program had over 86,000 participants and represents 52.0 MW of enrolled capacity.

- Residential DPP offers customers pricing options that are designed to incentivize reduced energy use during peak hours. At the end of 2025, the program had nearly 209,000 participants and represents 45.0 MW of enrolled capacity.

- The Residential Smart Thermostat Program uses cloud-based software deployed through the customer's Wi-Fi thermostat to optimize energy savings. As of 2025, the program had over 65,000 participants and represents 60.1 MW of enrolled capacity.

- The Business DR Contractual Program offers payment based on contractual agreement to reduce load by a contract amount during Midcontinent Independent System Operator, Inc. ("MISO") emergencies during all MISO seasons. The Business DR Contractual Program has set event, duration, and timeframe limits specified in the agreement. As of 2025, the program included 1,474 accounts and 279.8 MW of enrolled capacity.

- Business DR Rate Options includes the General Interruptible ("GI") and General Interruptible 2 ("GI2") rate provisions, Rate Energy Intensive Primary ("EIP"), and Long-Term Industrial Load Retention Rate ("LTILRR") which provide discounts, monthly on-bill incentives, market pricing signals, or a combination of these to C&I customers for reducing load during emergencies year-round. Each option does include specific criteria for entry. As of 2025, Business DR Rate programs had an approximate enrollment of 38 accounts and 259.5 MWs of enrolled capacity.

In addition, the Company recognizes that the Commission has recently clarified that DR programs, including Smart Thermostat and other customer-sited load flexibility offerings, are appropriately understood as a form of Virtual Power Plant ("VPP"). Consistent with the Commission's findings in its March 27, 2026 Order in Case No. U-21870, Consumers Energy's DR portfolio functions as an aggregated, dispatchable resource capable of providing multiple grid benefits, including peak load reduction, enhanced system reliability, and the avoidance or deferral of traditional supply-side and distribution investments. Accordingly, the Company evaluates and operates its DR programs not solely as individual customer programs, but as coordinated grid resources that support both

near-term operational needs and long-term planning objectives reflected in the Company's Distribution System Plans ("DSPs") and Integrated Resource Plans ("IRPs"). See related testimony on VPPs by Company witnesses Emily Duke and Scott McPhail.

A. Cost Details

Q. Please explain the O&M costs associated with the DR programs offered by the Company.

A. Projected O&M costs for the test year for these programs are $33.6 million and are included on Exhibit A-111 (AMG-4), page 1. Capital costs for these programs are projected to be $180,000 in the test year and are included in Exhibit A-12 (AMG-3), Schedule B-5.8. These programs are designed as a lower-cost, flexible capacity resource that can be used during times of peak electricity demand to mitigate system constraints and, ultimately, to reduce costs paid by customers. As aggregated resources, these DR programs operate collectively as a customer-sited VPP, allowing the Company to deliver grid services that are comparable to traditional infrastructure investments at a lower cost and with greater flexibility. This capital and O&M spending are related to enrolling (or "activating") customers interested in participating in DR and implementing DR programs.

Costs related to the DR Program are broken into three major categories – labor, contractor costs, and non-labor other.

- *Labor* spending related to DR programs is associated with internal labor resources that support the program through event operations, program management, marketing, data visualization & analytics, customer research, evaluation, and contractor support. These activities are critical in the deployment of voluntary DR programs as they require a different value proposition and resourcing than traditional electric utility service to bring to market and promote customer participation.

- *Contractor costs* are allocated to the three major contractors that Consumers Energy works with in the management of these DR programs – EnergyHub,

Honeywell, and Enel X. These costs cover activities such as managing thermostats for the Smart Thermostat Program, C&I customer portals used to dispatch event notification, incentives, installation fees for switches, thermostats, and the functional marketing costs related to digital, social, mailings, etc. Most of these contractor costs closely align with the number of customer enrollments and as enrollments continue to increase in conjunction with the Company's IRP, the Company will continue to see increased costs in these spaces related to incentives as it seeks to enroll new and retain existing customers in the face of audience saturation and looming requirements from MISO's DR reform. The Company also anticipates higher contractor Software as a Service ("SaaS") fees to manage these devices with the latest software upgrades. The Company's contracts with these contractors have financial and performance metrics included to ensure that Consumers Energy is achieving cost effectiveness.

- *Non-labor costs* are additional costs incidental to the program but not directly related to labor costs, for C&I programs most customer incentives are included in non-labor costs. When looking at capital costs for DR programs, the major contributor to cost is materials. For the residential program, the Company works with contractors for the installation of device cycling switches. For the majority of Business DR customer communications, equipment is installed to allow for dispatch communications during events and provide customers with the necessary tools to perform during events. The remaining customers receive communications that are manually triggered by Company employees.

Q. What benefit does the Company's DR Program provide?

A. Electric demand varies by season and the Company must secure sufficient capacity resources for any time of peak demand (plus a reserve margin). As a result, some generation resources are rarely fully utilized outside of high-demand summer months. DR programs help manage capacity need for peak demand, in lieu of additional supply-side electric generation, or capacity contracts. Ultimately, the Company's DR programs help balance Michigan's electricity needs to help protect the grid, react to emergencies and severe weather, and avoid the cost of additional generation infrastructure to serve peaks. Further, as discussed by Company witness Joshua W. Hahn, customers will receive $59.9 million worth of capacity value in Planning Year 2026/2027 from the MWs, or the Zonal Resource Credits, that the DR programs provide.

DR also provides the opportunity for customers to take better control of their energy usage, decrease their energy costs, and participate in the Company's Clean Energy Plan. Residential customers benefit from participating in DR programs by saving money when they shift flexible demand to hours when energy is less expensive. All customers benefit from DR reducing grid strain during peak demand periods because reducing grid strain offsets the Company's need to invest in more generation or capacity resources.

Most importantly, demand-side resources such as DR are essential to meeting climate goals and achieving the MWs approved in the IRP. The DR Program remains essential to the Company's long-term ability to achieve greater flexibility and improved sustainability over the long term.

Q. What is the Company's overall approach to DR in the future?

A. Looking forward, Consumers Energy will continue to expand and refine its DR portfolio consistent with the Commission's guidance regarding VPPs. The Company is actively evaluating opportunities to enhance aggregation, dispatchability, and integration of customer-sited resources across residential and business programs, and to ensure that these VPP-like capabilities are appropriately considered alongside traditional infrastructure solutions in distribution and resource planning. This approach supports system reliability, cost containment, and the Commission's expectation that grid needs be met using the most cost-effective mix of supply-side and demand-side resources.

B. Surcharge and Regulatory Framework

Q. Is the Company requesting approval of a DR surcharge in this case?

A. No. As shown in the rate design by Company witness Michael C. Grondin, Consumers Energy is not including a separate surcharge for the DR program. Based on the

Commission order in Case No. U-21637, DR is now included solely in rate cases as opposed to the previous methodology with a separate DR reconciliation filing. The Company's proposed incentive, spend and any under- or over-recovery from the DR program will be included in base rates, as it was prior to approval of the surcharge.

C. Residential DR

Q. Please explain the structure of the Residential DR Program.

A. The Company offers three Commission-approved Residential DR programs: a Device Cycling program, a DPP program, and a Smart Thermostat program.

Q. Is the Company proposing any changes to the Residential DR portfolio?

A. Yes, the Company is proposing changes to the DPP program as discussed below. The Company is not proposing changes to the Device Cycling program credit that was updated to $5 per customer-month in June through August because of the Order in Case No. U-21585. The latest value of MISO's Cost of New Entry ("CONE") is $137,510/MW-year in Zone 7, which is only 5% higher than the prior year and results in no change to the Device Cycling credit calculation approved in the previous rate case.

Q. Please describe the residential Device Cycling Program and the related customer benefits.

A. In the Device Cycling Program, the Company installs direct load control switches on air conditioning ("AC") units. The program ended in 2025 with 52.0 MW of capacity. When the Company activates a switch, it will cycle the output of the connected load by between 40% and 75%. At the end of an event, each system returns to normal operation. In exchange, customers receive a monthly bill credit of $5 during the billing months of June through August, as recently approved in the Company's prior electric rate case, Case No.

U-21585. Customers previously received a $25 enrollment incentive, but the Company discontinued this when the program was moved into maintenance mode. During DR events, customers reduce load during peak hours which translates into a shift in kWh from the peak to off-peak period, lowering bills.

Q. Please describe the residential Smart Thermostat Program.

A. The Smart Thermostat Program is for customers who have central AC, and a participating Wi-Fi-enabled smart thermostat and agree to participate in DR events. During a DR event, customers can expect their thermostat setpoint to adjust up to 4 degrees above their current setpoint to reduce strain on the electric grid during high demand days, in the summer months of June - August. The program uses cloud-based software deployed through the customer's Wi-Fi thermostat to perform a pre-emptive energy optimization (pre-cooling) of the home to achieve greater demand savings during the duration of the DR event.

Q. Please describe the direct benefits customers receive for participating in the Smart Thermostat Program.

A. Customers participating in the Smart Thermostat Program receive an incentive for signing up for the program. If the customer already has a participating (Google Nest, Ecobee, Honeywell, Emerson, Alarm.com, or Amazon smart thermostat) device, the customer will sign up through the Bring Your Own Device ("BYOD") path and receive a Pre-Paid Mastercard as an enrollment incentive. If the customer does not already have a participating Smart Thermostat, they can purchase a thermostat through the Consumers Energy Residential Online Store and receive an instant incentive credit toward the purchase of the new DR Pre-Enrolled Smart Thermostat. Both paths currently receive an annual Pre-Paid Mastercard at the end of event season for participation in the program.

Q. Please describe any changes the Company is proposing for the Smart Thermostat Program.

A. The Company will discontinue the use of Pre-Paid Mastercards as a customer incentive for the program. Instead, customer participation will be incentivized with a bill credit, as early as October 2026. This change will eliminate costs related to obtaining and mailing the Pre-Paid Mastercards, as well as reducing administrative costs and activities.

Q. Please describe the residential DPP Program.

A. The Company's DPP Program is designed to encourage customers to shift their energy consumption away from the hours of a DR event. Currently, the Company offers two pricing options under the program, Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"). The goals of the two pricing options are identical, but the approach to achieve them differs. The CPP option charges customers a significantly higher rate of $1/kWh of energy used during DR event hours. In exchange, customers are offered a discount on their rate during weekends, holidays, and all hours of the weekdays except 2 p.m. to 7 p.m. The CPP Program is generally referred to as a "stick" incentive - using strong pricing signals to reduce consumption during an event. Alternatively, the PTR option offers customers a payment for reducing their energy during DR events. This is currently a credit of $1/kWh of energy reduced during event hours as compared to their baseline use.

Q. Please describe the importance of PTR as a part of DPP and the Residential DR Portfolio.

A. The PTR Program is a critical component to the Company's overall residential DR portfolio because it provides customers a no-risk option to participate in DR. From a portfolio standpoint, the Company has seen a higher enrollment rate for PTR compared to

other DR offerings with 182,245 cumulative enrollments in 2025. DPP also has the highest rate of Low-Income enrollments. Although the enrollment rate for PTR is higher, the per customer demand savings are significantly lower than the rest of the portfolio (at 0.21 kW/customer, currently vs 0.92 kW per customer for the Smart Thermostat Program. The combination of a high conversion rate paired with low demand savings has influenced the Company's strategy to view PTR as an "entry-level" or "gateway" offering. Meaning, the Company plans to leverage the willingness of customers to participate in PTR to get them familiar with DR in a no-risk way before encouraging them to participate in a different program (primarily the Smart Thermostat Program) where demand savings to the customer and the Company are more predictable and controllable. Given the change in strategy to use PTR as a gateway DR program, the Company has made significant changes to reduce expenses for the program to improve cost-effectiveness. The Company: (1) has Discontinued the Customer Service Representative enrollment incentives as of December 31, 2025, and (2) is focusing primarily on low to no cost marketing channels including the Consumers Energy website during the time of move-in.

Q. Please describe any changes the Company is proposing for the PTR Program.

A. The Company is proposing to remove the credit offered to the PTR control group for the PTR Program. Currently, a $3 credit is applied to non-participating customers in the PTR control group during a DR event. The $3 credit significantly overstates the overall economic impact of the PTR program. Removing it for non-participant control group customers would help reduce program costs and allow Consumers Energy to trigger economic events more frequently, and with smaller subsets of customers, improving

cost-effectiveness. Please reference Company witness Brittani A. Gray's Exhibit A-16 (BAG-2), Schedule F-5 for proposed changes in related tariff language.

D. Business DR

Q. Please explain the structure of the Business Contractual DR Program.

A. Each business customer that signs up for the Business DR Contractual Program is contracted for a specified load (kW) reduction. The Company works with individual business customers to set up a demand reduction plan at their facility that will be implemented when a DR event is called. Business customers of different sizes participate through this process to create a business DR portfolio. When MISO expects the grid to be strained because of high electric demand or during periods of high market costs, the Company notifies participants within the Business DR Program of the need to reduce load. Customers then have 30 minutes to execute their curtailment plan (unless the event is scheduled at a specific future time). The resulting reduction in peak load is for the purpose of relieving stress on the electric system in a more cost-effective manner than purchasing capacity from the market or building additional generation resources.

Q. How does the Business DR Contractual Program differ from the Company's interruptible rates?

A. The Company's interruptible rate defines specific capacity and energy billing parameters, whereas the Company's Business DR Program provides a contract with customers to defining specific program parameters. With the interruptible rate options customers are charged a lower rate in exchange for a firm commitment to reduce demand by or to a specified amount during MISO events. Participants who choose to deviate from this

commitment during MISO events are assessed a significant financial penalty or are subject to higher real time market prices depending on rate or provision.

The Business DR Contractual Program also comprises demand curtailment commitments. But unlike the Company's interruptible rate options, customers choose to nominate an amount of demand they are willing to reduce during events at specific timeframes and dates for the program year. The contractual program has limits on the number of events, duration of events, and days in which events can be called. Customers receive payments for their performance during MISO Emergency Events for up to 250% of their nominated amount. The financial benefit to participating business customers is less significant with the Business DR Contractual Program than with the interruptible rate options, to recognize the reduced event risk timeframes and durations customers are exposed to.

Q. How are participants compensated for reducing their electric load during peak demand events?

A. Participants are compensated for capacity and energy reductions during events. The capacity payment is tied to kW of reduction nominated, and the energy payment is based on kWh reduction during events. Both are measured from an established baseline in accordance with MISO calculations. Compensation for capacity is based on the customer's contracted capacity reduction during the program enrollment period. The customer receives payment for energy based on performance during events. Incentive payments are priced for market competitiveness and are a component of the overall cost of having and managing a DR capacity resource.

Q. Do non-participating customers benefit from the Company offering a Business DR program?

A. Yes. The Company's Business DR Program provides a flexible, repeatable, and scalable capacity resource. The program benefits all Consumers Energy customers by reducing the need to purchase additional capacity during times of peak demand, thereby reducing the cost of providing power to all customers.

Q. Will these DR contracts be bid into MISO?

A. Yes. The Company will bid into MISO based on the portfolio capacity of participating customers. Each participating customer will be required to enter a contract with the Company, which outlines the terms of performance in keeping with MISO requirements for a Load Modifying Resource and payments as it relates to the contracted capacity and energy. Capacity payments are standardized at the same rate for all participating customers.

Q. Is the Company proposing other tariff-related changes for Business DR?

A. No. The Company is not proposing changes to the GI provision credits that were recently updated to $8.50/kW-month in summer months and $7.50/kW-month in non-summer months as a result of the Order in Case No. U-21585. The latest value of MISO's CONE is $137,510/MW-year in Zone 7, which is only 5% higher than the prior year and results in no change to the GI credit calculation approved in the previous rate case.

Q. Is the Company enhancing existing elements of the Business DR Contractual Program or developing new offerings?

A. Yes, the Company has transitioned the Business DR Contractual Program to a seasonal structure and launched its first year-round season on June 1, 2025. Early results from this

new approach have been encouraging, with seasonal contracts demonstrating improved participation and customer engagement. The Company anticipates continued growth in registered load each season as it refines and optimizes the program. The Business DR Contractual Program will also continue to explore different payment structures that are more performance and event based. The flexibility built into the contractual framework allows the Company to provide timely program upgrades and adapt to evolving customer market needs.

Q. Please discuss the Company's plan for Utility led testing beginning in 2026.

A. The Company has filed an application with the MPSC in Case No. U-22068 requesting updated tariff language allowing customers to waive the utility led testing requirement for 2026/2027. The intent of this waiver is to allow both the Company and customers to better prepare for MISO-led testing while mitigating program risks. If approved, the Company will still hold optional testing in 2026/2027 to allow customers to practice for the upcoming required testing, and to optimize Company processes and communications to ensure future testing success. If not approved, the Company is prepared to hold mandatory testing in 2026.

E. DR Pilot

Q. Please describe the pilot approved in the March 27, 2026 Order in Case No. U-21870.

A. The Company's Whole Home Optimization Demand Response pilot will allow the Company to test how customers respond to and interact with energy usage and demand analytics, customer-controlled responses and behavior, and aggregation of resources within their home using a whole home optimization approach.

The Company will test this technology specifically with its residential customers given the past implementation of Time-of-Use ("TOU") rate structures (RSP 1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting DERs in the home, including battery storage and electric vehicles, to shift energy off-peak.

While the Whole Home Optimization pilot expands the technical breadth of DER aggregation beyond existing DR offerings, it builds on the same foundational VPP principles already embedded in the Company's current DR portfolio.

The Company will work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility.

Q. Please provide an update on the Whole Home Optimization Demand Response Pilot.

A. The Company has engaged with eight interested vendors to date regarding the Whole Home Optimization DR pilot. As a next step, the Company intends to further evaluate these vendors by narrowing the field and conducting formal demonstrations of each vendor's software, platform, customer recruitment and retention strategies, and technical capabilities. These demonstrations will include participation from key internal stakeholders across Demand Response, Electric Distribution, Electric Supply, Research, and Regulatory teams to identify potential cross functional benefits of the pilot and to evaluate whether additional functionality could support other operational or planning needs that are consistent with the objectives of the pilot.

Based on these evaluations, the Company anticipates inviting a limited number of vendors to participate in a formal Request for Proposal process, with the goal of selecting a preferred vendor and initiating the pilot in 2027.

The Company's preferred vendor will offer a Grid Edge Distributed Energy Resource Management System software and/or VPP capabilities that's capable of integrating and managing a broad range of DERs beyond smart thermostats. Such resources may include, but are not limited to, residential batteries, electric vehicles ("EVs"), electric vehicle supply equipment ("EVSE"), whole home generators, and smart home energy management systems. The pilot will assess each technology's ability to provide load reduction with customer-owned devices through a BYOD approach.

In addition, the Company will assess customer experience metrics, including enrollment processes and opt-out behavior, to better understand customer impacts associated with expanded DER aggregation. These evaluations will also consider the scalability of customer participation and device performance to determine which DERs can be deployed at sufficient scale to serve as reliable, repeatable, and cost-effective resources for future planning and operational use cases.

At the conclusion of the pilot, the Company will evaluate overall performance and determine whether continuation or expansion is warranted, considering system needs, cost effectiveness, and regulatory considerations. The Company will seek alignment with Staff prior to significant changes and will ensure appropriate customer communications and protections in either case.

F. DR Reconciliation

Q. The December 18, 2025 Order in Case No. U-21637 stated that each investor-owned utility shall file its demand response cost request in a general rate case. Has Consumers Energy complied with this requirement?

A. Yes. The following section details the Company's reconciliation for its demand response program. Issues presented below are also pending in Case No. U-21906 and the Commission's Order could influence aspects of the 2025 reconciliation.

1. PROJECTED AND ACTUAL COSTS

Q. What were the total DR portfolio costs in 2025?

A. Capital spending for the 2025 DR portfolio totaled ($482,868) as shown on Exhibit A-112 (AMG-5), page 1, line 9, column (a). O&M spending for the DR portfolio totaled $29,443,083 which includes business customer incentive payments of $8,569,472. Customer tariff credits of $8,225,218 are shown on Exhibit A-112 (AMG-5), page 1, line 6, column (a). Based on amounts approved in Case Nos. U-21389 and U-21585, the Company's actual 2025 DR capital spending was, in total, $2,646,691 lower as shown on Exhibit A-112 (AMG-5), page 1, line 9, column (c) and the Company's actual O&M spending was $6,435,642 lower than approved amounts as shown on Exhibit A-112 (AMG-5), page 1, line 5, column (c). The lower actual investment reflects the Company's efforts to reduce operating costs in program delivery to improve cost-effectiveness. This included decisions to put programs in maintenance mode that did not provide cost-effective DR options for customers.

Q. What is the variance of the DR revenue requirement for the program year?

A. The difference in the actual revenue requirement as compared to the approved revenue requirement for the DR Program portfolio is $9,591,929. This over recovery variance is shown on Exhibit A-112 (AMG-5), page 1, line 12, column (c).

Q. How does the Company propose to address the difference in revenue requirements?

A. The Company proposes to refund the over-collection and collect the performance incentive through base rates. As shown in the Company's revenue requirement presented by Company witness Hannah L. Patton, the over-collection total prior to interest is $9,591,929 and totals $10,421,543 after interest in included. As described above, the Company is proposing to eliminate the DR surcharge.

Q. Is the Company proposing a 2025 DR performance incentive for approval by the Commission?

A. Yes, the Company is requesting a 2025 performance incentive of $7,703,553 to be recovered through base rates, not a surcharge. I will discuss the Company's proposed methodology and calculation of the 2025 DR performance incentive later in my testimony.

2. RESIDENTIAL DR

a. Projected and Actual Residential Costs

Q. What were the actual Residential DR portfolio costs in 2025?

A. The costs for the 2025 Residential DR portfolio included capital expenditures of ($898,765) and O&M expenses of $11,911,495 (including $1,346,959 of Customer Tariff Credits) as shown on Exhibit A-112 (AMG-5), page 2, lines 6, 11, and 17, column (a).

Q. How do the actual 2025 Residential DR Program costs compare to the expected costs from Case Nos. U-21389 and U-21585?

A. The costs for the 2025 Residential DR Program were approved in Case Nos. U-21389 and U-21585 and included $1,948,090 for capital expenditures and $17,468,493 for O&M expenses (including $3,049,230 of Customer Tariff Credits). 2025 actual capital expenditures were $2,846,855 below, 2025 actual O&M expenses were $2,507,768 below, and 2025 Customer Tariff Credits were $1,702,271 below the approved amounts as shown on Exhibit A-112 (AMG-5), page 2, lines 11, 6, and 17, column (e).

Q. What drove the variance between 2025 planned and actual costs?

A. For O&M, the primary driver of variance was within the STP. The Company underspent on marketing costs by approximately $500K, and rolled out offline device management in 2025. Marketing expenses for STP consisted of paid media, paid search, direct mails, emails, banners, and events. The variance was, in part, driven by a shift in forecasted spend for direct mails due to a partnership with Google and the Consumers Energy Online Store, allowing the Company to share the cost of printing on various materials. The offline device management initiative has helped clean up enrolled thermostats that have not been connected to Wi-Fi and controllable for at least 90 days or more. During the roll out of this effort, the Company worked with the program implementor, EnergyHub, to send a series of emails to the offline device participants, as an effort to get the device reconnected and controllable again. After a series of six email attempts went out to these customers, the Company removed those that took no action to reconnect their device. This offline device management effort will be conducted on a quarterly basis to ensure that devices enrolled in the program remain consistently connected and controllable. As part of the broader

program cleanup, EnergyHub identified and removed inaccurate or unsupported enrollments, including legacy records carried over during the prior vendor migration and devices no longer supported by one of the thermostat manufacturers. These actions reduced unnecessary device fees and incentive payments. More importantly, they strengthen overall program performance by ensuring enrollment accuracy, improving event reliability, and increasing the effectiveness of dispatched devices, resulting in stronger kW-per-device outcomes. For capital expenditures, the primary driver of variance was within the Device Cycling program There were two credit adjustments applied to this program; a credit of $932,000 in June 2025, and a credit of $89,000 in January 2026 that was included as a 2025 transaction.

Q. What components make up the capital expenditures for the Device Cycling Program?

A. Capital costs for the Device Cycling Program include: (i) management labor costs for the call center, scheduling, and route planning; (ii) switch installation, removals, and materials; (iii) permits and processing costs; and (iv) other direct costs such as warehousing, equipment, and taxes.

Q. What components make up the O&M costs for the Device Cycling Program?

A. The O&M cost components for the Device Cycling Program include: (i) program management and support fees; (ii) retainage related to program performance and delivery milestones; (iii) marketing activities supporting program awareness; and (iv) device maintenance services required to support ongoing operations.

Q. What components make up the costs for the DPP Program?

A. The DPP Program is comprised entirely of O&M costs. These costs include: (i) program management, IT support, and Evaluation, Measurement, and Verification; (ii) customer

acquisition expenses including direct mail, and program materials; and (iii) other direct costs such as software licensing and taxes.

Q. What components make up the costs for the STP?

A. The STP is comprised entirely of O&M costs. These costs include: (i) program management, IT support, and Evaluation, Measurement, and Verification; (ii) customer acquisition expenses including incentives, website development, direct mail, bill inserts, and other customer communications and program materials; and (iii) other direct costs such as annual device fees, software licensing, and taxes.

b. <u>Residential MW Achievements</u>

Q. What were the Company's residential MW achievements for 2025?

A. The Company enrolled 53.8 MW for the Device Cycling Program, 41MW for the DPP Program, and 58.1 MW for the STP for a spring (May 31) residential portfolio achievement of 152.9 MW. The Company enrolled 50.3 MW for the Device Cycling Program, 44.4 MW for the DPP Program, and 59.4 MW for the STP for a fall (November 30) residential portfolio achievement of 154.2 MW, shown on Exhibit A-113 (AMG-6).

Q. Please explain the details upon which the achievement is based.

A. At the end of the fall season, the Company had 83,882 participants in the Device Cycling Program, 206,404 participants in the DPP Program, and 64,534 participants in the STP as shown on Exhibit A-113 (AMG-6).

Q. What were the 2025 per customer load reduction assumptions for the Residential DR Device Cycling, STP, and DPP programs?

A. The Company's 2025 projected peak demand reductions were based on the post-2023 DR season event evaluations performed by third-party evaluator Cadmus, as no statistically

significant events were called during the summer 2023 season. As presented in the Company's 2022 DR Reconciliation filing, Case No. U-21410, the Company adopted per customer response rates of 0.60 kW, 0.25 kW, 0.21 kW, and 0.92 kW per customer for the Device Cycling, CPP, PTR, and STP programs, respectively, for the 2025 DR Event Season.

3. BUSINESS DR

Q. Please describe the cost components of the Business DR Contractual Program.

A. Business DR Contractual Program costs are divided into three major segments: (i) materials; (ii) labor; and (iii) incentives. The first segment includes the cost of all material, infrastructure to manage and validate participation, and marketing material associated with the customer education process. Infrastructure includes meters, software, software licenses, platform fees to enable program management and visualization, as well as metering and validation of program outcomes. The second segment includes cost to manage the programs, staff the network operations center, and sales staff to acquire Business DR Contractual Program customers. The third segment constitutes payments to participants. The incentive payments to DR participants reference the payments made for capacity and energy supply.

Q. What are the 2025 Business DR Contractual Program costs included in this filing?

A. The 2025 Business DR Contractual Program costs included in this reconciliation are capital expenditures of $415,897 and O&M expenses of $17,531,588, as shown on Exhibit A-112 (AMG-5) page 2, lines 24 and 21, column (a). The O&M expenses include customer payments of $8,569,472, as provided on Exhibit A-112 (AMG-5), page 2, line 20.

Customer Tariff Credits of $6,878,259 are also provided on Exhibit A-112 (AMG-5), page 2, line 28.

Q. How do the actual Business DR costs compare to the expected costs from Case Nos. U-21389 and U-21585?

A. Business DR Program 2025 capital investment was $200,164 above approved amounts and 2025 O&M expense was $2,952,910 below approved costs as shown on Exhibit A-112 (AMG-5), page 2, lines 24 and 21, column (e).

Q. What drove the variance between planned and actual costs?

A. The capital investment variance was primarily driven by lower-than-projected costs for customer equipment installations. The O&M variance was primarily attributed to lower-than-expected customer incentive payments.

Q. Did the Company conduct any Business DR pilots in 2025?

A. No.

4. UTILIZATION OF DR RESOURCES

Q. Please describe the utilization of DR Resources.

A. DR resources are utilized to reduce strain on the grid during MISO emergency events. The Company may also deploy Residential DR for non-emergency events in either the Day-Ahead market, when electric loads are expected to exceed a trigger condition, or in the Real-Time Energy markets. In addition to emergency events called by MISO, the Company may call up to 10 economic events in the summer for the Residential Device Cycling Program, up to 14 events for the Residential DPP Program, and up to 7 events for Residential STP.

Q. Under what conditions did Consumers Energy deploy its DR resources during 2025?

A. The Company called one economic event for residential demand response programs. Event 1 on 07/15/2025 resulted in 54.2 MW response from DR Residential STP and 27.2 MW from DR Residential Device Cycling.

Q. Does the Company have experience with other VPPs besides DR?

A. Yes. In addition to operating its current Demand Response portfolio as an aggregated, dispatchable VPP resource, the Company has a long track record of implementing other customer- and system-side programs that function as VPPs by reducing peak demand and energy consumption. These include, for example, the Company's TOU rates, its Distributed Generation ("DG") program, its EWR programs, and its Conservation Voltage Reduction program. Collectively, these efforts demonstrate that the Company has successfully deployed programs that provide measurable, verifiable demand and energy impacts and can reduce the need for more costly infrastructure investments.

Q. What costs have these programs avoided for customers?

A. These programs have avoided (or deferred) the need to invest in substantial capacity and energy resources by reducing peak demand and total energy consumption. For example, under the current regulatory construct, the Company's Demand Response efforts achieved 4,252.3 MW of cumulative demand response capability over the 2016 through 2025 period. In addition, the Company's EWR programs have produced cumulative first-year energy savings of 7,961 GWh from 2009 through 2025. These measurable outcomes illustrate that Consumers Energy's existing VPP-type programs have delivered significant customer and system benefits and support the Company's continued focus on scalable, least-cost alternatives to traditional infrastructure where appropriate.

5. REVENUE REQUIREMENT CALCULATION

Q. Please describe the Exhibit A-114 (AMG-7).

A. Exhibit A-114 (AMG-7) provides the revenue requirement calculation for capital spending associated with the DR programs for the calendar year 2025. Exhibit A-114 (AMG-7), columns (b) through (d), provide the approved total revenue requirement calculation included in rates for the calendar year 2025, and columns (e) through (g) provide the revenue requirement calculation for 2025 incorporating actual DR capital spending. Exhibit A-114 (AMG-7), line 6, provides the difference between the actual 2025 revenue requirement and the approved 2025 revenue requirement.

Q. Please explain how the revenue requirement for both the approved and the actual DR programs was developed.

A. The revenue requirement for the DR programs uses the approved and actual rate base for the 2025 period multiplied by the pre-tax rate of return, resulting in a return-on-investment amount. The depreciation expense and Real and Personal Property ("R&PP") tax is added to the return on investment resulting in the total revenue requirement, as shown on Exhibit A-114 (AMG-7), line 5.

Q. Please explain how the approved total rate base amounts on Exhibit A-114 (AMG-7), line 1, were developed.

A. Approved plant in service ("PIS"), construction work in progress ("CWIP"), and depreciation reserve balances for the DR programs were developed by taking the average of the balances at 12 months ended December 2024 and 12 months ended December 2025, based on prorated approved amounts in Case No. U-21585, the Company's 2024 electric rate case and Case No. U-21389, the Company's 2023 electric rate case. Then, the approved

total rate base was calculated by adding the average PIS and average CWIP balances, minus the average depreciation reserve balance.

Q. Please explain how the actual total rate base amounts on Exhibit A-114 (AMG-7), line 1, were developed.

A. Actual PIS, CWIP, and depreciation reserve balances for the DR programs were developed by taking the average of the actual balances at 12 months ended December 2024 and 12 months ended December 2025, consistent with the reconciliation period presented in this case. Then, the actual total rate base was calculated by adding the average PIS and average CWIP balances, minus the average depreciation reserve balance.

Q. Exhibit A-114 (AMG-7), line 2, provides a prorated pre-tax rate of return of 7.57%. What is the source of this pre-tax rate of return?

A. The pre-tax rate of return of 7.57% is the prorated amount calculated using the final orders in Case No. U-21389 and Case No. U-21585.

Q. How is the approved and actual depreciation and R&PP tax expenses as shown on Exhibit A-114 (AMG-7), line 4, calculated?

A. Approved depreciation expense has been calculated by applying the depreciation and property tax rates prorated between the final orders in Case No. U-21389 and in Case No. U-21585 to depreciable balances, as calculated using prorated approved capital spending. Actual depreciation expense has been calculated using the 2025 depreciation recorded by the Company and applying the prorated property tax rates to depreciable balances, as calculated using actual capital spending.

6. LEVELIZED COST CALCULATION

Q. Please describe Exhibit A-115 (AMG-8).

A. Exhibit A-115 (AMG-8) is the levelized cost calculation for the 2015 to 2045 period.

Q. Did the Company evaluate DR programs and the DR portfolio for cost-effectiveness?

A. Yes. The Company calculated a levelized cost of the DR portfolio in Exhibit A-115 (AMG-8) based on the 30-year period from 2015 to 2045. The analysis is based on actual costs and MW enrolled for the 2025 reconciliation period along with projected costs and MW enrollment for the 2015-2045 timeframe. The enrollments, MW, and costs are in line with the Company's 2021 IRP filing in Case No. U-21090, adjusted to account for changes that have occurred since. Based on this analysis, the DR portfolio including the proposed performance incentive has a levelized cost of $86,587 per MW-year, which is lower than the 2025/2026 Planning Year CONE of $130,930/MW-year.

2025 PROGRAMS	LIFECYCLE LEVELIZED COST $/MW-YEAR	ENROLLED MW
Air Conditioning Peak Cycling ("ACPC")	$188,504	50.4
Dynamic Peak Pricing ("DPP")	$22,003	44.4
Smart Thermostat Program ("STP")	$158,351	59.4
Commercial & Industrial ("C&I")	$60,915	209.5
DR Portfolio Excluding Performance Incentive	$76,399	693.4
DR Portfolio Including Performance Incentive	$86,587	693.4

The Company's DR program provides flexible MW reductions that prevent or delay the Company's need to invest in more expensive supply side resources. The Company recognizes the importance of cost effectiveness when determining how to allocate

resources, but cost effectiveness is most important at the portfolio level. MW growth in DR, as long as the portfolio remains cost effective, is a high priority, and to ensure a robust and competitive portfolio, the Company should be able to experiment with new technologies and new ways of reaching underutilized markets. The Company's DR portfolio, as it stands today and as planned into the future, remains a cost-effective resource that can be relied upon in the IRP process.

While lifecycle levelized costs demonstrate overall portfolio performance, marginal levelized costs are the appropriate metric for determining whether continued operation of a demand response program is more economical than procuring new capacity. The Company has also calculated a levelized marginal cost of its DR programs, which shows below that these programs are below CONE.

2025 PROGRAMS	LIFECYCLE LEVELIZED COST $/MW-YEAR
Air Conditioning Peak Cycling ("ACPC")	$73,238
Dynamic Peak Pricing ("DPP")	$2,026
Smart Thermostat Program ("STP")	$115,636
Commercial & Industrial ("C&I")	$67,614
DR Portfolio	$69,833

Overall, the Company has found that the DR portfolio offers a cost-effective addition to meeting the Company's resource needs.

7. PERFORMANCE INCENTIVE

Q. Please describe the Exhibit A-116 (AMG-9).

A. Exhibit A-116 (AMG-9) shows the Company's proposed 2025 DR performance incentive calculation using the shared savings calculation developed as part of meetings with MPSC

Staff ("Staff") as required by the approved settlement agreement in Case No. U-21647, the Company's 2023 DR Reconciliation.

Q. Is the Company proposing a 2025 DR performance incentive for approval by the Commission?

A. Yes. A performance incentive encourages the Company to continue to invest in DR. Because of the successful history with the DR performance incentive, the Company has continued to grow its cost-effective DR programs and is choosing to invest in DR over other resources. The Company has, and will continue to operate DR to meet the requirements of the approved IRP and past orders requiring voluntary DR. Though, absent a performance incentive, innovation like the proposed pilot with its heavy skew towards O&M costs instead of capital intensive investments in traditional generation earning a return on the equity portion of financing, would be at risk, effectively stalling DR growth into new areas.

As stated above, the Company has met all the necessary requirements to earn the full financial incentive originally approved by the Commission in Case No. U-20164 and updated in subsequent Commission orders. As illustrated in Exhibit A-115 (AMG-8), lines 1 and 2, the Company achieved 693.4 MW of peak demand reduction as of December 31, 2025 which exceeds the IRP target of 641 MW.

Q. Is the Company proposing the percentage of spend methodology for the 2025 performance incentive, consistent with the prior reconciliation orders?

A. Yes. The Company met with Staff following the order approving settlement in the 2023 DR Reconciliation case, Case No. U-21647, and developed a shared savings mechanism without a cap structure. The proposed calculation uses the levelized costs of the Company's

DR programs, less 75% of CONE, weighted by the number of MW registered with MISO as Load Modifying Resources. The sum of the difference, multiplied by a shared savings factor, is the Company's proposed performance incentive. The Company proposes 50% of the weighted difference between the levelized cost of the DR programs and 75% of CONE to be the performance incentive, as shown on Exhibit A-116 (AMG-9).

Q. How does the Company propose to recover the 2025 DR Performance Incentive?

A. The Company proposes to recover the DR financial incentive of $7,703,553 as shown on Exhibit A-116 (AMG-9), line 5, through base rates.

Q. Does the Company propose any other changes for the performance incentive?

A. Yes. As described in more detail below, the Company proposes that new DR pilots be excluded from the shared savings calculation for the performance incentive and that IRP MW targets no longer be required for the Company to receive a performance incentive.

Q. Why should new DR pilots be excluded from the performance incentive shared savings calculation?

A. Pilots are inherently not cost effective in the early stages. The Company is testing new products and approaches to find what works best. The Whole Home Optimization pilot proposed to begin in 2026 will test customer-owned smart home energy management systems, battery storage, and load management devices. Innovation would be stifled as the Company would not invest in pilots if it were penalized with a reduced performance incentive. Therefore, the Company proposes to exclude pilots from the shared savings calculation for a period of three years from its commencement, at which point the Company would decide to continue and include in the shared savings performance incentive calculation or terminate with no additional consequences.

Q. Why should the DR levels that were approved in the Company's IRP no longer remain the target for the Company to receive the performance incentive?

A. For 2024 and beyond, if the Company's performance incentive is calculated using the shared savings mechanism, hitting the IRP MW targets may no longer be prudent. Instead, the Company would be incentivized, with the shared savings calculation, to increase MW enrolled and registered with MISO in the most cost-effective way. If DR MW in the IRP remained the target, the Company could be forced to invest in less cost-effective programs to drive MW higher. The Commission should approve the removal of the MW target for DR and instead incentivize cost effectiveness through the shared savings mechanism.

8. DR PROGRAM COST DEFERRED ACCOUNTING

Q. Please explain the Commission's requirement on accounting for DR Program costs.

A. Per the September 15, 2017 Order in Case No. U-18369, "costs associated with DR should follow deferred regulatory accounting with return." However, the Commission stated that "deferred regulatory accounting for capital expenditures and O&M is not permitted for items that have been previously approved and already included in rates."

Q. Was deferred regulatory accounting treatment applied on over/underspending related to the 2025 DR Program costs?

A. Yes, it was. Actual revenue requirement for the reconciliation year was $9,591,929 lower when compared to the approved revenue requirement for the 2025 program year (see Exhibit A-112 (AMG-5)). The total revenue sufficiency of $9,591,929 was deferred and recorded as a regulatory liability on the Company's books.

Q. Will carrying costs on the over-recovery balances be recorded, and if so, at what interest rate?

A. Yes, the Company is recording carrying costs on over-recovery balances starting from January 2025 until the regulatory balances are fully refunded. The carrying cost rate used for the over-recovery balances will be the Company's short-term borrowing rate. This process is consistent with the application of carrying costs in the Company's EWR Program.

a. <u>DR Program Incentive Accounting</u>

Q. Is the Company proposing a DR financial incentive in this case?

A. Yes.

Q. Is the DR financial incentive revenue classified as normal revenue?

A. No, the DR incentive revenue falls under an alternative revenue program according to Accounting Standards Codification ("ASC") 980-605-25.

Q. What is alternative revenue?

A. Alternative revenue is generally segregated into two programs. The first program adjusts billings for the effects of abnormal weather patterns, energy conservation efforts, or from broad external factors such as a general recession. Revenue recorded through decoupling falls under this program. The second program provides for additional billings if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or improving customer service. Revenue recorded through the DR financial incentive falls under this latter program.

Q. What are the alternative revenue recognition criteria?

A. ASC 980-605-25 states that revenue recognition is appropriate when all of the following criteria are met:

- Criteria A: The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment of future rates by the regulator does not preclude the adjustment from being considered automatic;
- Criteria B: The amount of additional revenues for the period is objectively determinable and recovery is probable; and
- Criteria C: The additional revenues will be collected within the 24 months following the end of the annual period in which they are recognized.

Q. Does the DR Financial Incentive in this proceeding meet Criteria A?

A. Yes, Criteria A has been met. The Commission's July 18, 2019, Order in Case No. U-20164 authorized a financial incentive mechanism for Consumers Energy beginning with its 2019 DR Reconciliation.

Q. Does the DR incentive in this proceeding meet Criteria B?

A. Yes, the DR incentive is objectively determinable under the mechanism approved by the Commission.

Q. Does the DR incentive in this proceeding meet Criteria C?

A. Yes, but only if the collection of the incentive occurs within 24 months from the period the incentive was recognized.

Q. What is the Company's proposed collection period for the annual DR incentive revenue?

A. The annual DR financial incentive revenue is recognized on Consumers Energy's books at the end of the calendar year it pertains to. In order to comply with the 24-month collection requirement (Criteria C) it needs to be certain that the annual incentive will be fully

collected within 24 months from the date it is recorded in the Company's financial statements.

Q. What are the implications if the revenue is not fully collected within 24 months from the end of the incentive year?

A. If the DR incentive is not fully collected within 24 months from the end of its incentive year, GAAP would require a determination that the revenue was recorded out of period and should have been recognized when billed to the customer. The requirements of ASC 980-605-25 stipulate that the revenue must be collected within 24 months and allows no flexibility. Failing to collect within 24 months from the end of its incentive year would then require a reversal of the DR incentive revenue that was already recognized by the Company.

III. ELECTRIC VEHICLES

Q. Please describe Exhibit A-12 (AMG-10), Schedule B-5.9.

A. Exhibit A-12 (AMG-10), Schedule B-5.9 reflects the capital spend for the historical, bridge, and test years for the Transportation Electrification Program ("TEP") per approvals from prior rate cases. Make-ready capital includes metering and utility-side upgrades such as transformers for new services as previously approved. No additional spend from prior approvals is requested, but the timeline has changed. The Company had anticipated that all remaining capital for the initial fast charging pilot authorization would be complete in 2025; however, factors such as National Electric Vehicle Infrastructure ("NEVI") contracting delays and the Federal Highway Administration's decision to suspend EV charging infrastructure funding has extended the completion date for multiple projects.

Q. Please describe Exhibit A-117 (AMG-11).

A. Exhibit A-117 (AMG-11) shows a Summary of Actual and Projected O&M Expenses for Electric Transportation Deferred Asset Costs.

Q. Please describe Exhibit A-118 (AMG-12).

A. Exhibit A-118 (AMG-12) shows the Transportation Electrification Plan Cost Benefit Analysis.

A. TEP Program

Q. Please summarize the Company's approved TEP programs and their results.

A. Per the Final TEP Order in Case No. U-21492,[3] the Company's TEP is centered on long-term strategies to optimize EV charging load to the benefit of all customers, and investments, incentives, programs, and expenditures that are reasonably expected to increase transportation electrification in the Company's electric service territory. The Company's latest TEP is publicly available online[4] and was filed June 1, 2026. The Company incorporates the report by reference, and I plan to sponsor it as an exhibit through revised direct testimony or rebuttal testimony as appropriate. To accomplish the goals of optimizing load and increasing transportation electrification, the Company continues to support utilizing a portion of the additional revenue from EV load growth to pay for TEPs. This is optimal because EV drivers pay for the TEPs and the Company is not raising rates to implement the TEPs. Moreover, while EV drivers fully pay for the TEPs, all customers benefit from the load optimization as the same infrastructure is used to power more EVs, generating additional revenue that mitigates rate

[3] MPSC Case No. U-21492, January 23, 2025 Order, at Filing: U-21492-0018

[4] TEP Docket

pressure. This is clearly demonstrated in the "Cost Benefit Analysis" tab of Exhibit A-118 (AMG-12), which shows the TEP's cost recovery of $203 million (line 1) results in approximately $1.1 billion in Net Present Value of marginal revenue from additional electricity sales from EV charging over the 2025-2035 period. Since the previous TEP filing, the permanent TEP programs have achieved over 95% off-peak charging across managed categories, and more than 88% off-peak charging when including Direct Current Fast Charging ("DCFC") loads. To optimize load and increase EV adoption, the Company is focused on three key strategic program areas within the TEP umbrella – Residential, Public and Fleet:

1. PowerMIDrive Residential Program Overview

Being able to reliably and cost-effectively charge at home is critical for most EV drivers, thereby directly impacting EV adoption. If customers do not have access to convenient home charging, they are less likely to adopt the technology. Moreover, most homes in Michigan were constructed before EVs became mainstream, meaning that load management is critical given constraints at the panel and potentially the residential distribution system.

The single-family programming implements a combination of educational outreach, TOU rate, and rebate and incentive programs for off-peak charging at Level 2 ("L2") circuit levels of 50 amps or less (40 amps continuous for 9.6 kW) consistent with residential design standards. The up to $500 rebate (up to $1,000 for income-qualified customers) serves to get EV drivers engaged with their utility and the program, as utility service is not historically part of purchasing a vehicle. From the initial customer contact driven by the rebate offer, EV specialists can educate customers on TOU rates and why

off-peak charging is beneficial. Once enrolled, the monthly off-peak charging incentive of $10 (for 12 months) helps reinforce off-peak charging behavior through all four seasons leading to long-term off-peak charging behavior.

Furthermore, the residential team has implemented a referral incentive program, as customers most likely to purchase an EV are those who know someone with an EV. Customers in the program are key components of helping to grow enrollment via other EV drivers and potential drivers they know. Finally, the team also implemented the dual-cord L2 and splitter incentive,[5] which is designed to prevent EV charging peaks beyond the residential design standards by continuing to utilize a single 50 amp circuit (40 amp continuous) as additional EVs are purchased or leased (a likely occurrence given that most EV drivers remain EV drivers) to spread the load over a longer off-peak time at a maximum 9.6 kW load. Without an incentive for dual-cord L2 or use of a power-sharing splitter, it is more likely that continued EV adoption would result in multiple EV charging circuits in a home, leading to peak loads significantly greater than 9.6 kW and higher ramp rates.

2. PowerMIDrive Public Program Overview

Public charging advances both grid optimization and EV adoption. Grid optimization is achieved by incentivizing lower-power charging (L2 and sometimes Level 1 ("L1")) at strategic off-peak times at locations that fit the customer's use case, including multifamily property charging, community charging, or charging at an overnight destination, and workplace charging.

[5] A dual-cord L2 utilizes two plugs that power share from the same L2. A splitter is a device that plugs into a single outlet, and then two separate L2 power share from that device. Both technologies work via a single NEMA 14-50 outlet.

Critically, the Multifamily Property EV Charging rebate program incentivizes multifamily property owners to invest in EV charging as an amenity for residential tenants, helping ensure equitable access to off-peak charging for residents. The multifamily property must have at least four individual tenant dwellings at the site. Through this program, commercial customers at multifamily locations are eligible for up to $7,500 for installation of a minimum of two L2 charge ports, or two National Electrical Manufacturers Association ("NEMA") 14-50 outlets on a 100-amp service.

The Community Charging rebate program promotes equity because it encourages commercial and industrial customers in the municipality sector (e.g., cities, townships, or other community entity) to install EVSE in areas that might otherwise lack access to lower-power charging by creating L2 infrastructure within walking distance of multifamily residences. Through this program, commercial customers are eligible for up to $7,500 for installation of a minimum of two L2 charge ports, or two NEMA 14-50 outlets, or five (5) 20-amp 120-volt outlets on a 100-amp service.

The Overnight Destination rebate program is designed to improve charging infrastructure accessibility in locations where EV drivers are most likely to charge for longer off-peak time periods when traveling. Through this program, commercial and industrial customers in the overnight destination sector (e.g., hotels, motels, campgrounds, long-term airport parking) are eligible for up to $7,500 for installation of a minimum of two L2 charge ports, or five 20-amp 120-volt outlets on a 100-amp service.

The Workplace Charging program is focused on supporting and incentivizing businesses to install chargers at their workplace. Through this program commercial customers are eligible for up to $7,500 for installation of a minimum of two L2 charge

ports on a 100-amp service. Businesses who participate in the program and open their charging stations to the public for overnight charging are eligible for a $10,000 enhanced rebate.

All Workplace Charging programs require EVSE to be separately metered, on a TOU Rate, and agree to deploy signs for display at the charger encouraging off peak charging.

3. PowerMIFleet Program Overview

The PowerMIFleet program is targeted at businesses who are interested in electrifying their fleet. This program is an attractive offering for school districts looking to electrify their bus fleet; or can be used any other business looking to electrify, who meet program requirements. This program incentivizes customers with a rebate of up to $7,500 for installation of two L2 chargers, and a rebate of $15,000 for installation of one long duration Direct Current ("DC") port. The PowerMIFleet program also offers complimentary fleet assessments to help assess project scale, costs, and returns.

Q. What new program elements or expansions are included in the 2026 TEP Biennial Plan compared to the 2024 TEP Biennial Plan?

A. **PowerMIDrive Residential Program**: The 2026 TEP expands on the foundation established in the 2024 TEP by allowing participation under the Consumers Energy standard TOU rate, in addition to the Nighttime Savers and Residential Smart Hours TOU rates and builds on the existing Smart Charging Incentive ("SCI") program without altering its core structure. The SCI program has demonstrated strong effectiveness in encouraging off-peak EV charging, supporting system reliability, and helping to maintain downward pressure on rates for all customers. Post-enrollment analysis conducted with the program's

third-party vendor indicates that approximately 90% of participants maintained their off-peak charging behavior after completing the 12-month incentive period. This sustained behavior confirms that the program successfully establishes lasting charging habits. Expanding eligible rate options is expected to broaden program participation and further strengthen the program's overall impact.

PowerMIDrive Public Program: For the PowerMIDrive Public program, Consumers Energy is making targeted changes with the goal of broadening eligibility requirements to meet customer demand and reduce customer costs.

1. The Company proposes increasing the maximum eligible charging output per port in its public L2 EV rebate programs, including Workplace Charging, Multifamily Charging, Overnight Destinations, and Community Charging, to 11.5 kW. Supporting L2 chargers up to this level better aligns the rebate programs with the charging capabilities of newer electric vehicles, allows drivers to gain more useful range during short-to-moderate parking periods, and improves the long-term value of infrastructure investments funded by ratepayers, without creating material additional impacts to the electric distribution system. This proposed maximum is consistent with peer utilities such as DTE Energy's public charging approach, which effectively supports L2 installations at or below approximately 11.5 kW and reserves higher power levels for DC fast-charging programs. In addition, this proposal aligns with statewide planning assumptions used in the EV Charging Infrastructure Study (Phase 2) prepared for the Michigan Office of Future Mobility & Electrification and the Michigan Department of Labor & Economic Opportunity by Michigan State University, which modeled public L2 charging locations and quantities assuming charger power ratings of approximately 11 kW. By aligning rebate eligibility with these planning assumptions, the Company's program is better positioned to support Michigan's long-term transportation electrification goals and accommodate future EV charging needs.

2. For businesses and public places with 10 or fewer parking spaces, the Company proposes removing the separate meter requirement. This change enables small customers on a secondary rate to participate in the program without being required to install a new meter, which can add significant customer costs and become a barrier to EV adoption. Based on an analysis of the Company's current project development pipeline, which includes 18 projects, the average cost of new meter installation is approximately $15,000. For small businesses, this added cost can make participation cost-prohibitive, particularly where limited parking capacity restricts opportunities to add chargers over time as a means of recovering upfront costs. By eliminating this requirement for smaller

sites, the program lowers barriers to participation, expands access to public charging in a wider range of neighborhoods, and supports more geographically and economically diverse deployment of EV charging infrastructure, consistent with the Commission's equity and accessibility objectives.

3. For primary-rate customers served under the General Primary Demand ("GPD") rate the Company is requesting removal of the separate meter requirement within the tariff. This change will enable customers served on the GPD rate to join the program without the requirement of installing a new billing meter. Primary customers who are on the GPD rate are already incentivized to charge off peak through their rate. Requiring a separate meter introduces additional costs to both the customer and the company. There is additional complexity due to installing company equipment on privately owned facilities, limiting access and clear maintenance responsibilities. Additionally, the Company's analysis of off-peak charging shows a success rate of 87.7% off-peak charging for Workplace & Fleet programs, demonstrating a proven track record of business customers adhering to off-peak charging, making the separate meter redundant.

4. The Company proposes enhanced, income-qualified rebate offerings for nonprofit organizations that serve vulnerable and underserved populations. These rebates would support both electric vehicle supply equipment and electric vehicles, including cargo and transit vans, helping nonprofits reduce fuel and maintenance costs while continuing to provide essential services to the communities they serve. By lowering transportation expenses, this proposal allows limited nonprofit resources to be redirected to core mission activities and advances transportation electrification in communities that may otherwise face barriers to adoption. Historically, similar support was provided on a limited, ad hoc basis through Fleet make-ready resources. The Company now proposes to formalize this support within the PowerMIDrive Public program portfolio and existing budget, without an increase in funding, by establishing a transparent, application-based process for eligible nonprofits. This approach improves consistency and access while advancing equity by ensuring organizations that serve low-income, disadvantaged, and mobility-limited populations can meaningfully participate in the benefits of electrification.

PowerMIFleet Program: Within the PowerMIFleet program, Consumers Energy is requesting removal of the separate meter requirement for primary customers served under a GPD rate. This request is based on the same reasoning listed previously under the PowerMIDrive Public program changes.

Within this TEP filing the Company is proposing enhanced rebates for businesses electrifying fleets of at least 20 vehicles, within an underutilized area of the grid. This is

targeting a segment with growing demand and meaningful load potential, where our current incentives are falling short. This will allow us to better incentivize large fleets, while also optimizing our grid by pushing electrification to underutilized areas. Underutilized areas of the grid are parts of the electric system where existing infrastructure has available capacity that is not being fully used during most hours, especially during peak demand periods. Costs for these enhanced rebates will be reallocated from the existing budget.

Q. What components of the prior TEP cycle are being discontinued or modified, and why?

A. **PowerMIDrive Residential Program**: For the TEP biennial filing, the program will incorporate the standard TOU rate (RSP) to expand eligibility to customers who may not participate in more narrowly defined rate options, reducing enrollment barriers and enabling broader adoption of smart charging behaviors. This expanded access is expected to increase participation and further strengthen the program's overall system and customer benefits.

PowerMIDrive Public Program: As part of this filing, the Company proposes discontinuing the $20 monthly Multifamily Dwelling Unit ("MDU") bill credit included in the prior TEP cycle. This bill credit was originally introduced to encourage off-peak charging behavior at multifamily properties, and it has been highly successful in achieving that objective. Even after the 12-month credit period ended, participants demonstrated strong and sustained improvements in off-peak charging, with off-peak usage increasing from 72.3 percent under the 2024 TEP to 81.7% in 2025 and 87.3% in 2026. The Company attributes this sustained behavior to the combined impact of separate metering, enrollment in TOU rates, educational signage, and increased charger availability at multifamily

properties. Given these durable outcomes, the Company does not anticipate that sunsetting the bill credit will lead to a regression in charging behavior. Discontinuing the MDU bill credit will allow program funds to be redirected toward additional rebates.

PowerMIFleet Program: The Company is not requesting any discontinuations or modifications to the Fleet programs beyond what is listed in the previous question.

Q. Is the Company proposing any tariff-related changes for the Transportation Electrification Programs?

A. Yes, the Company proposes the following changes to the tariff:

PowerMIDrive Residential Program:

- Include the Standard TOU Rate RSP
- Remove the On-Bill Installment Payment Plan
- Remove the requirement that Residential customers use a pre-approved installer for EV charging installations
- Remove the $20/month AMI Monitoring Credit for enhanced Multifamily Dwelling customers

PowerMIDrive Public Program:

- Revise eligibility language to be broader for qualifying locations available to the public
- Remove separate meter requirement for businesses with 10 or fewer parking spaces (as described above)
- Remove the separate meter requirement for primary-rate customers served under the GPD rate (as described above)

PowerMIFleet Program:

- Remove the separate meter requirement for primary-rate customers served under the GPD rate (as described above)

Please reference Company witness Gray's Exhibit A-16 (BAG-2), Schedule F-5 for proposed changes in related tariff language.

Q. Why is the Company proposing to remove the installment payment plan for residential customers from the tariff?

A. Following further evaluation, the installment payment plan option is being proposed for removal from the PowerMIDrive program due to financial and budgetary considerations. Specifically, continuation of the installment payment plan created an increased risk to funds within the approved TEP budget, as the deferred payment structure exposed program dollars to potential non-recovery and variability in cash flow. This risk was determined to be inconsistent with the financial controls and fiscal safeguards established for the program under the approved TEP budget parameters.

Additionally, a cost-benefit analysis determined that the incremental cost required to implement, administer, and maintain the installment payment plan—including system modifications, vendor support, and ongoing operational oversight—outweighed the anticipated customer and program benefits. Given these factors, retaining the installment payment plan was not considered a prudent or cost-effective use of program funds.

Based on this assessment, the decision was made to eliminate the installment payment plan option in order to reduce financial risk, maintain compliance with approved budgetary constraints, and ensure responsible stewardship of program resources.

Q. Are any customers currently participating in the installment payment plan under the PowerMIDrive Residential program, and has the Company received inquiries regarding this provision?

A. No. At this time, there are no customers participating in the installment payment plan under the PowerMIDrive Residential program. Additionally, the Company has not received any customer inquiries regarding the availability or use of this provision. The lack of

participation and customer interest further supports the Company's proposal to remove the installment payment plan from the tariff.

Q. Why is the Company proposing to remove the requirement that Residential customers use a pre-approved installer for EV charging installations from the tariff?

A. After a comprehensive review of program utilization and customer behavior, the Company discontinued the use of pre-approved installers within the PowerMIDrive program due to limited customer adoption and reduced program value.

From July 2022 through July 2025, approximately 10% of PowerMIDrive applicants (1,120 of a total 11,072) requested assistance from the program's installer network. Of those customers requesting assistance, only 34% (384 of a total 1,120) ultimately utilized a pre-approved installer for their EVSE installation. When evaluated across all PowerMIDrive applicants during this period, only 3% (384 of a total 11,072) used a pre-approved installer.

This data demonstrates that the vast majority of PowerMIDrive participants elected to secure installation services independently, regardless of the availability of a pre-approved installer network. Given the low overall utilization rate, the pre-approved installer option did not provide sufficient value to a meaningful portion of customers to justify its continued inclusion in the program.

Additionally, maintaining a pre-approved installer network requires ongoing administrative oversight, contract management, and compliance monitoring. In light of the limited customer usage, eliminating these administrative costs and operational efforts was determined to outweigh the benefits provided by the option.

Based on this analysis, the Company determined that discontinuing the pre-approved installer option better aligns the PowerMIDrive program with actual customer preferences, improves administrative efficiency, and supports effective stewardship of program resources, while continuing to allow customers the flexibility to select qualified installers of their choosing.

Q. What is the rationale behind proposing to remove the $20/month AMI Monitoring Credit for enhanced Multifamily Dwelling customers?

A. As discussed above, the Company proposes to discontinue the $20 monthly MDU bill credit included in the prior TEP cycle. The combined effects of separate metering, time-of-use rates, educational signage, and increased charger adoption have driven durable off-peak charging behavior, reducing the need for a recurring bill credit and supporting sustained program benefits without anticipated behavioral change.

Q. The Company proposes to revise the eligibility language in the PowerMIDrive Public section of the tariff. How does removing this language describing specific public charging locations strengthen the PowerMIDrive Public program?

A. Removing location-specific language from the PowerMIDrive Public tariff strengthens the program by ensuring the eligibility criteria accurately reflect the full range of public L2 charging use cases, including overnight destinations, multifamily charging, community charging, and workplace charging. This revision improves clarity and consistency across the program, reduces administrative complexity, and allows the tariff to remain flexible as public charging needs evolve, without requiring future revisions. By focusing eligibility on publicly accessible L2 charging rather than narrowly defined site types, the tariff better

supports program scalability and provides greater transparency for customers, installers, and regulators.

Q. Why is the Company proposing to remove the requirement that DCFC rebate recipients must be served on General Service Primary Rate GP from the tariff?

A. The Company proposes to remove tariff language that limits DCFC rebate eligibility to customers served on the General Service Primary ("GP") rate. Removing this restriction lowers an unnecessary barrier to participation, expands eligibility across appropriate rate classes, and improves customer access to the PowerMIDrive DCFC rebates without changing program intent or cost recovery. This update ensures the tariff reflects current customer conditions and supports broader deployment of DCFC infrastructure.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

BRITTANI A. GRAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Brittani A. Gray, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

QUALIFICATIONS

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Product Owner in the Rates and Regulation Department.

Q. Please describe your educational and professional experience.

A. In January 2010, I was hired by Consumers Energy as a Customer Service Representative within the Company's Customer Contact Center. In April 2013, I joined the Virtual Contact Center's Customer Value Initiative Team researching industry best practices. In February 2014, I joined the Business Center within the Business Customer Care Department and became a subject matter expert in Complex Billing and Commercial & Industrial rates. In April 2019, I was promoted as a Business Customer Solutions Account Manager where I worked directly with customers on a variety of reactive requests related to Complex Billing, Rates and Tariffs, Field Operations, Outage and Reliability, and Project Support. I ensured any questions, concerns, or requests were addressed and resolved to provide the best possible customer experience. In May 2023, I joined the Rates and Regulations Department as a Tariff Analyst and in May 2024, I was promoted to Senior Tariff Analyst. In those roles, I supported the development and filing of electric tariffs, prepared testimony exhibits for regulatory proceedings, conducted rate and monthly bill comparisons, and supported rate implementation activities following Michigan Public Service Commission ("MPSC" or the "Commission") orders.

I have since been promoted to Senior Product Owner and Rate Implementation Lead. My current responsibilities include leading rate implementation efforts for approved rates and tariff revisions; translating regulatory and tariff requirements into system and process design; coordinating billing system configuration and testing; ensuring accurate and timely implementation of Commission-approved rates; and serving as a liaison among regulatory, legal, billing, IT, and customer-facing organizations. I also provide subject matter expertise on complex billing scenarios and support post-implementation validation and issue resolution. In addition, I have attended Michigan State University's Institute of Public Utilities Accounting and Rate Making Course.

Q. Have you previously testified before the Commission?

Yes. I have filed direct testimony in the following cases:

Case No. U-21374	Voluntary Green Pricing programs;
Case No. U-21585	Electric General Rate Case; and
Case No. U-21870	Electric General Rate Case.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the Company's proposed tariff language changes to its electric rate schedules.

EXHIBITS

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-120 (BAG-1)		Summary of Tariff Changes;
Exhibit A-16 (BAG-2)	Schedule F-5	Proposed Electric Tariff Sheets (M.P.S.C. No. 14 Redlined Version); and

Exhibit A-238 (BAG-3) Rate Case Customer Communications.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please explain Exhibit A-120 (BAG-1) – Summary of Tariff Changes.

A. Exhibit A-120 (BAG-1) provides a summary and explanation of the changes proposed in this filing to the tariffs in the Company's Electric Rate Book.

Q. Please describe Exhibit A-16 (BAG-2), Schedule F-5, Proposed Electric Tariff Sheets (MPSC No. 14 Redlined Version).

A. Exhibit A-16 (BAG-2), Schedule F-5 contains all proposed changes to the Company's current electric tariffs in the Rate Book for Electric Service (M.P.S.C. No. 14 – Electric), presented in redlined format. Existing tariff language proposed for deletion is shown with red strikethrough formatting, while new proposed language is indicated by blue underlined and italicized formatting. Some changes are discussed in the testimony of other Company witnesses, such as the rationale for price changes to the Company's electric rate schedules, which are supported by the Company's rate design witness, Michael C. Grondin.

Q. Please describe Exhibit A-238 (BAG-3), Rate Case Customer Communications.

A. Exhibit A-238 (BAG-3) reflects the Company's implementation of new customer communication requirements ordered in Case No. U-21637 related to rate case requests. The exhibit provides representative visual examples showing how rate case messages will be presented to customers with both dollar and percentage bill impacts. These examples illustrate customer bills, a dedicated website landing page, including the website home page and mobile application home screen. This exhibit is provided to demonstrate how the

Company will implement the Commission directed changes and to include the required preview of customer rate case messaging as part of this filing.

Q. Please explain the changes to New Service Connection Fees.

A. The Company proposes to update the overhead and underground new service connection fees to implement the Commission's directive in Case No. U-21870 regarding the incorporation of variable cost considerations in service connection charges. Consistent with that direction, the proposal removes the currently approved flat fees and reintroduces a dollar-per-foot fee structure that varies based on the length and type of service installed, allowing charges to reflect differences in the scope of facilities required for individual service connections.

Q. What are the proposed new service connection fees?

A. The proposed tariff sheets include dollar-per-foot charges of $10.20 per foot for Residential customers and $17.20 per foot for General Service customers. These values represent updated service connection charges derived from historic per-foot rates, adjusted to reflect the cumulative effects of inflation over time. The development and cost support for these fees are sponsored by Company witness Jennifer M. Partlan.

Q. Please explain the changes to C6.1 Overhead Extension Policy.

A. The Company proposes to update the overhead line extension fees in Rule C6.1 to reflect current cost conditions, as these fees have not been updated for several decades. The proposal updates the charge that applies when an overhead line extension exceeds 600 feet, while leaving the overall policy framework unchanged. In addition, the Company proposes to increase the one-time refund available to Residential customers who connect directly to

the distribution line. This change updates the refund amount without modifying eligibility requirements or how the refund is calculated or applied.

Q. Please explain the proposed changes to Rule C10.3 Experimental Advanced Renewable Program ("AR Program").

A. The Company proposes to clarify the treatment of customers upon expiration of their AR Program contract by specifying that, unless the Company determines that enrollment is not appropriate based on the customer's generation and applicable charges, such customers will be enrolled in the Simple Renewable Program ("SRP") with notice. Customers retain the ability to discontinue participation or select another eligible Company-offered program or contract at any time prior to or following contract expiration.

Q. Why is the Company proposing to automatically enroll customers in SRP upon contract expiration?

A. Absent a defined transition, some customers experienced periods following expiration of their AR Program contract during which they were not enrolled in a renewable program and were not compensated for energy produced, which led to customer confusion and administrative inefficiencies. Establishing a default enrollment in the Simple Renewable Program provides customers with a clear and predictable path forward, helps avoid uncompensated generation, and streamlines administration for both customers and the Company. Enrollment will occur unless the Company determines that enrollment is not appropriate based on the customer's generation and applicable charges.

Q. Please explain the proposed changes to Rule C19 Transportation Electrification Programs ("TEPs").

A. Sponsored by Company witness Alex M. Gast, the Company proposes several revisions to the Transportation Electrification Programs tariff. These changes are intended to streamline program administration, remove unused or unnecessary provisions, and update eligibility and metering requirements to better align with customer participation and program objectives. Specifically, the proposed changes include:

- Removing the On-Bill Installment Payment Plan;
- Expanding eligibility for the PowerMIDrive Residential Program to include the Standard TOU Rate;
- Eliminating the requirement for residential customers to use a pre-approved installer for EV charging installations;
- Removing the $20/month Advanced Metering Infrastructure ("AMI") Monitoring Credit for enhanced Multifamily Dwelling customers;
- Broadening eligibility language for qualifying public charging locations; and
- Removing the separate meter requirement for businesses with 10 or fewer parking spaces and revising separate metering requirements.

Q. Why is the Company proposing to discontinue the On-Bill Installment Payment Plan?

A. The Company proposes to discontinue the On-Bill Installment Payment Plan due to the absence of customer participation and because the IT enhancements required to support the option are not cost-effective. Further details are provided by Company witness Gast.

Q. Please explain the updates to eligibility for PowerMIDrive rebates and AMI Monitoring.

A. The proposed tariff revisions update eligibility criteria for PowerMIDrive rebates and AMI Monitoring by removing certain rate-based restrictions that previously limited participation. Under the revised language, customers taking service under a broader set of

eligible rate schedules may participate, with the exception of customers served under the Residential Service Secondary Non-Transmitting Meter Rate ("RSM"). Customers on Rate RSM remain ineligible because non-transmitting meters do not provide the interval data necessary to support these programs.

Q. What changes are being proposed to metering requirements for EV charging?

A. The proposed tariff revisions clarify when separate metering is required for participation in the PowerMIDrive Public and PowerMIFleet programs. Customers taking service under time-of-use rates, including GSTU and GPTU, are required to be separately metered. Customers served under non-time-of-use rates, including GS, GSD, GP, and GPD, may participate without separate metering. In addition, the tariff specifies that parking facilities with ten or fewer parking spaces may participate without separate metering, while facilities with more than ten parking spaces are required to separately meter electric vehicle charging equipment.

Q. Please explain the changes to Sheet Nos. D-17.00, D-38.00, and D-42.00.

A. The Company proposes to remove the $3 credit currently applicable to control group customers under the Peak Time Rewards ("PTR") Program. The proposed tariff revisions eliminate this credit from the PTR provisions, which simplifies program administration and aligns the tariff language with the Company's updated program design. Further discussion of the program-level rationale associated with this change is provided by Company witness Gast.

Q. Please describe the Company's proposed electric heating rate and any related implementation considerations.

A. In Case No. U-21870, the Commission directed the Company to propose a new electric heating rate applicable to Residential customers. While the rate design for the proposed electric heating rate is addressed by Company witness Grondin, the Company is requesting a six-month implementation period following Commission approval to allow sufficient time to configure, test, and implement the new rates in the Company's billing systems. This implementation period is necessary due to the Company's ongoing SAP S/4HANA system migration and is intended to ensure accurate billing and system readiness prior to the rate becoming effective.

Q. Please explain the changes to the Large Economic Development Rate ("LEDR").

A. The Company proposes adding a Power Factor Adjustment to the LEDR. This is consistent with power factor adjustments previously approved in Case No. U-21585 and is further supported by Company witness Laura M. Connolly. Because this adjustment introduces a new billing component for LEDR, the Company is requesting additional time following Commission approval to configure, test, and implement the necessary system changes. This additional implementation period is needed to align with the Company's ongoing SAP S/4HANA system migration.

Q. Please explain the proposed changes to the General Service Unmetered Lighting Rate ("GUL").

A. The Company proposes revisions to the GUL tariff to close the rate schedule to new unmetered lighting installations and to provide for the orderly transition of existing GUL customers to the General Unmetered Light-Emitting Diode Lighting Rate ("GU-LED") as

lighting installations are converted to LED. Under the proposed tariff, all new unmetered lighting installations will take service under the GU-LED rate. Existing non-LED luminaires installed prior to the effective date may remain on the GUL rate until conversion to LED is completed or until the customer elects to terminate service. Upon conversion, service will be transitioned to the GU-LED rate schedule, and all applicable terms, conditions, and charges of that rate will apply.

Q. Why does the Company propose closing Rate GUL to new business?

A. Closing the GUL Rate to new business aligns the tariff with the Company's current unmetered lighting technology offerings and the availability of lighting equipment. As discussed by Company witness Daniel A. Schmoekel, manufacturers have discontinued or are discontinuing high-intensity discharge ("HID") lighting products, and LED technology is now the Company's standard offering for unmetered lighting service. Directing new installations to the GU-LED rate ensures consistency between the tariff and the lighting technologies the Company provides.

Q. Does the proposed tariff require immediate conversion of all existing GUL installations to LED?

A. No. The proposed tariff does not require immediate system-wide conversion of existing GUL installations. Instead, it establishes how service will be treated when a conversion, replacement, or upgrade occurs. When an existing luminaire is converted to LED, either through Company maintenance activities or at the customer's request, the installation will no longer be eligible for service under the GUL rate and will be billed under the GU-LED rate.

Q. Are there any other tariff changes being proposed by the Company?

A. Yes. The remainder of the Company's proposed tariff changes are described in Exhibit A-120 (BAG-1), Summary of Tariff Changes. This exhibit provides a summary and explanation of all the tariff changes being proposed by the Company in this case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

ANGEL L. GREEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Angel L. Green, and my work address is One Energy Plaza, Jackson, MI 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Lean Strategy Manager.

Q. Please review your educational and business experience.

A. I hold a bachelor's degree in Business Administration with a specialization in Leadership and Governance from Davenport University, and an MBA with an emphasis on Organizational Excellence from Central Michigan University. Since joining Consumers Energy in 2005, I have held multiple roles over the past two decades focused on advancing performance metrics through lean methodologies across gas, electric, and customer operations. For the last four years, I have been accountable for leading cross-functional teams dedicated to driving performance improvement and achieving targets associated with the Employee Incentive Compensation Plan ("EICP") operational goals.

Q. What are your responsibilities as a Senior Lean Strategy Manager?

A. In the Senior Lean Strategy Manager role, I am responsible for the development, governance, and administration of the EICP operational goals. This includes but is not limited to the development of annual goals and associated targets, facilitating the development of plans to support goal achievement, ensuring the Company's lean operating system is leveraged to manage performance at various levels of the organization, and ensuring internal reporting standards are met.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have testified in Case No. U-21981, the Company's Gas Rate Case currently pending before the Commission.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose is to provide support for Consumers Energy's request for rate recovery for the test year employee compensation costs related to the EICP operational goals. Specifically, I will outline the operational goals included in Consumers Energy's EICP and how they provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-121 (ALG-1)	2025-2026 EICP Operational Goals;
Exhibit A-122 (ALG-2)	2025 Customer Benefits: Employee Safety;
Exhibit A-123 (ALG-3)	2025 Customer Benefits: Culture Index – Reduced Employee Turnover; and
Exhibit A-124 (ALG-4)	2025 Customer Benefits: Reliability.

Q. Please explain the process for establishing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial goals to focus on for the next year. The EICP operational goals are established by analyzing progress on the Company's strategic initiatives and developing key performance indicators that focus on driving performance improvement. The Company establishes operational goals grounded in delivering customer value through safe, reliable, affordable, and clean energy service across the business. Operational goals include both companywide objectives and utility-specific priorities, as appropriate based on the nature of the work and customer

outcomes. These goals apply to all eligible employees and incentivize achievement through daily continuous improvement and the application of the Company's Lean operating system, the CE Way. Operational goals are developed in partnership with the Company's leadership team and are approved annually by the Board of Directors. The process for developing annual targets is outlined later in my testimony.

Q. What operational goals make up the 2025 EICP portfolio?

A. The EICP operational goals for 2025 include Employee Safety, Culture Index, Customer Experience Index, Electric Reliability, Waste Elimination, and Methane Emission Reduction. As outlined in Company witness Amy M. Conrad's testimony, the Company is not seeking recovery for Waste Elimination due to the financial nature of the operational goal. As outlined in Exhibit A-70 (AMC-1), operational goals have not changed significantly from the 2025 to 2026 plan year; however, targets have changed to align to industry trends and drive continuous improvement.

Q. Please explain the Employee Safety goal.

A. The Employee Safety goal for 2025 was composed of three components: (1) Recordable Incident Rate; (2) High Risk Injuries; and (3) Fatalities. The Recordable Incident Rate accounts for 30% of the metric and is measured using the Occupational Safety and Health Administration ("OSHA") industry standard. High-Risk Injuries account for 70% of the metric and include both OSHA recordable and non-recordable incidents with the potential for resulting in a severe injury or fatality. The Edison Electric Institute's ("EEI") Safety Classification Learning Model is leveraged as the industry standard for reporting and High-Energy Serious Injury or Fatality ("HSIF") and Potential Serious Injury or Fatality ("PSIF") are included. If there is a fatality, there is a 0% payout for the Employee Safety

operational goal in its entirety. Please refer to A-122 (ALG-2) for additional information on the calculation method. In 2026, (2) High Risk Injuries will be replaced, and the goal will be composed of three components: (1) Recordable Incident Rate (2) Serious Injury Incidence Rate; and (3) Fatalities. The Recordable Incident Rate will account for 20% of the metric and is measured using the OSHA industry standard. Serious Injury Incidence Rate will account for 80% of the metric. These changes have no impact on the recovery request being made in this filing but will be included as metrics starting in the Company's 2027 Electric Rate Case.

Q. What is the Serious Injury Incidence Rate?

A. The Serious Injury Incidence Rate measures the frequency of serious injuries and includes HSIF and low-energy serious injuries or fatalities ("LSIF") as defined by EEI. It is calculated as: Serious Injury Incidence Rate = (Serious injury events x 200,000) / total hours worked, which standardizes the rate to 100 full-time workers. The Serious Injury Incidence Rate focuses on serious injuries, is benchmarkable against EEI peers, and is normalized for exposure through a rate.

Q. Why is the Employee Safety goal included in the EICP?

A. Employee Safety is foundational to the success of the Company. Creating and maintaining a safe workplace and culture shows the Company's commitment to its coworker's wellbeing and their ability to go home safely every day. When employees work safely it translates to delivering safe, reliable, affordable, and clean energy services to customers—while completing the work more efficiently, and avoiding costs associated with injuries. Customer benefits associated with Employee Safety are outlined later in my testimony.

Q. Please explain the Culture Index goal.

A. The Company uses an all-employee survey to determine the Culture Index, which is made up of three indices: (1) Engagement; (2) Empowerment; and (3) Diversity, Equity, and Inclusion. The indices are measured leveraging industry standards established by Korn Ferry, and data is collected leveraging the Qualtrics survey platform. Each of the three indices are derived by averaging the favorability score from employee responses. Additional information on the calculation method is outlined in Exhibit A-121 (ALG-1).

Q. Why is the Culture Index goal included in the EICP?

A. The Culture Index goal aims to enhance employee experience and engagement. Gallup's meta-analysis shows that companies with high employee engagement have 10% higher customer loyalty and engagement, 14% higher productivity, 51% less turnover, 78% lower absenteeism, and 32% fewer quality defects, outcomes that directly support improved service quality and greater value for customers compared to organizations with low engagement[1]. Benchmark data indicates that peer utilities have a turnover rate of 7.3%, while the Company's four-year historical average is 2.2%. Gallup estimates turnover costs at 1.5-2.0 times the employee's salary. By maintaining a 2% competitive advantage over peers and using a 1.5 multiplier as the conservative end of Gallup's estimate, the Company avoids at least $3,329,682 in annual turnover costs. Exhibit A-123 (ALG-3) shows the calculation in further detail.

[1] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx%23ite-285704

Q. Please explain the Customer Experience Index goal.

A. The Customer Experience Index is an industry standard developed and administered by Forrester[2] to measure the quality of customer service based on three questions: Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable? The metric focuses on the following experiences: (1) Billing and Payment; (2) Outage; (3) Moving; (4) Field; and (5) Other across the following channels: (1) Digital (website and mobile application); (2) Live agent; and (3) the Interactive Voice Response ("IVR"). Please refer to A-121 (ALG-1) for additional information on the calculation method.

Q. Why is the Customer Experience Index goal included in EICP?

A. The Customer Experience Index goal focuses on ensuring when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (*e.g.*, reducing the number and duration of customer calls, which benefits the Company and the customer) and customer value (*e.g.*, quick, easy, and enjoyable solutions for customer experiences).

Q. Please explain the Electric Reliability goal.

A. The Electric Reliability goal is measured using the System Average Interruption Duration Index ("SAIDI") as the industry standard to measure and improve performance. SAIDI has two components for measuring and reporting reliability as follows:

(1) The System Average Interruption Frequency Index ("SAIFI") – this indicates the frequency of outages that occur due to system condition, configuration, and related external conditions (e.g. weather patterns, forecasts, etc.)

[2] https://www.forrester.com/research/

(2) The Customer Average Interruption Duration Index ("CAIDI") – this indicates how long interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.

SAIDI results are calculated by multiplying SAIFI and CAIDI. SAIDI is calculated excluding Major Event Days ("MEDs") to normalize performance data for unusually severe weather.

Q. Why is the Electric Reliability goal included in EICP?

A. Benchmarking through J.D. Power and internal customer data indicate that electric reliability is one of the top three drivers of overall customer satisfaction. Accordingly, the Company is committed to providing safe, reliable, and affordable electric service. The Electric Reliability goal is directly aligned with the Company's Electric Reliability Roadmap[3] (*i.e.*, Electric Distribution Infrastructure Investment Plan) and will position the Company for future success as electric demand increases. Improving electric reliability also provides an economic benefit to customers and is discussed later in my testimony.

Q. Please explain the Methane Emissions Reduction goal.

A. The Methane Emissions Reduction goal aims to reduce fugitive methane emissions associated with the Company's natural gas system.

Reductions are achieved through the following work activities:

(1) Retiring and replacing miles of natural gas distribution mains;

(2) Retiring and replacing natural gas distribution services (both vintage and non-vintage materials);

(3) Completing natural gas distribution system leak replacements; and

[3] https://www.consumersenergy.com/-/media/CE/Documents/company/electric-generation/ediip-report.pdf

(4) Performing well plug and abandonment activities.

Reductions are measured in metric tons, leveraging the emission factors outlined in the Environmental Protection Agency's Greenhouse Gas Reporting Rule, 40 CFR Part 98 Subpart W.

Q. Why is the Methane Emission Reduction goal included in EICP?

A. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate Plan, which outlines goals for Michigan to achieve economy-wide carbon neutrality no later than 2050 and reduce greenhouse gas emissions by approximately 28% from 2005 levels by 2025. In November 2023, the Clean Energy Law was enacted as the legislative implementation of key elements of that plan, including clean energy, storage, and emissions reduction objectives. The EICP Methane Emissions goal supports these state objectives and aligns with the Company's Natural Gas Delivery Plan, which is founded on the Company's commitment to providing safe, reliable, affordable, and increasingly clean natural gas for Michigan. The goal also reflects the Company's objective to achieve net-zero methane emissions by 2030.

Q. Please explain the annual target setting process.

A. Targets for the EICP operational goals are proposed by subject matter experts, leveraging industry benchmarking, best practices, long-term strategies, annual work plans, and historical performance data. These targets are then recommended to the Company's officer team to validate that targets are both challenging and achievable and will result in the delivery of customer value. The officers present recommendations to the Board of Directors for final approval.

Q. Has the Company quantified customer benefits that are tied to EICP?

A. Yes. Although specific quantification of benefits is not feasible for every metric, the Company has evaluated direct quantitative customer benefits for three key operational goals: Employee Safety, Electric Reliability, and Culture Index. For the remaining goals, the Company has assessed indirect and/or qualitative benefits that are directly aligned with what customers consistently indicate is most important to them, namely safe operations, reliable service, ease of doing business, and responsive customer support, regardless of whether those benefits can be readily expressed in dollar terms.

Q. Is there a direct tie between the design of the EICP operational goals and desirable benefits for customers?

A. Yes. There is a direct tie between the design of the EICP operational goals and desirable benefits for customers. The operational goals focus on delivering customer value through safe, reliable, affordable, and clean energy services—all desirable benefits for customers.

Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be commensurate with the programs' costs?

A. Yes. Company witness Conrad and I present evidence in support of including EICP costs at the 100% payout level, proving that including these costs will not result in excessive rates, and the costs of the EICP will, at a minimum, be commensurate with the programs' costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

Q. How have you evaluated the EICP goals' direct quantitative benefits?

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2026, when met, will reduce incidents by 27% from the four-year historical average. The resulting reduction in lost workdays and medical expenses is $1,244,202 of annual direct savings. Expected indirect savings, calculated using OSHA's recommended multiplier, totals $923,038 of annual savings. Together, the projected annual direct and indirect savings that accrue to the benefit of the customer totals $2,167,241. Exhibit A-122 (ALG-2) provides the calculation of these savings.

The second metric that can be readily translated to quantifiable cost avoidance for customers is electric reliability. Using estimates from the Berkley National Laboratory's Interruption Cost Estimate "ICE" Calculator[4] the average improvement from the four-year historical performance resulted in annual economic benefits to customers of approximately $110 million. Exhibit A-124 (ALG-4) provides the calculation of these savings.

Third, there are benefits related to the Culture Index created by reducing employee turnover for Company employees with <1-4 years of tenure by 2% as compared with industry peers. The average annual salary of an employee with tenure of <1-4 years of experience is $102,578, and lower turnover avoids costs equal to at least 1.5 times the employees' annual salaries. This means that by reducing turnover in this employee group by 2%, when compared to utility peers, the Company will conservatively avoid costs of

[4] ICE Calculator | Interruption Cost Estimate Tool

$3,329,682 up to $4,439,576. Exhibit A-123 (ALG-3) shows the calculation in further detail.

Q. How have you evaluated the EICP goals' other qualitative benefits?

A. The Methane Emission Reduction goal is essential to achieving the Company's goal of net-zero methane emissions from its natural gas system by 2030, which supports the Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The direct economic benefits for customers are difficult to calculate, but the qualitative benefits are beyond dispute. Improved Customer Experience is another benefit of achieving EICP goals that is difficult to quantify but nonetheless quite real. The benefits of pursuing improvement in Customer Experience have been discussed above.

Q. Why have you included both electric and natural gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization and operational goals are established in critical areas to drive the delivery of customer value through safe, reliable, affordable, and clean energy services across electric and natural gas operations. The quantified benefits of Employee Safety, the Culture Index, and Electric Reliability show that benefits to electric customers clearly exceed the employee incentive compensation amounts that Consumers Energy has requested be included in rates in this case.

Q. What is the Company's reasoning for having a Methane Emission Reduction goal attributed to electric business employees?

A. The EICP goals align with Company priorities, providing targets for the entire organization. Prioritizing Electric Reliability and Methane Emission Reduction is essential,

as previously mentioned in my testimony. The Company quantifies EICP benefits to ensure electric customers pay for the benefits they receive. Given the combined operations, and the majority of non-union employees supporting both electric and gas operations, it is reasonable to include both Electric Reliability and Methane Emission Reduction goals in the EICP.

Q. What portion of the direct benefits that you have quantified above do you conclude benefit electric customers?

A. A portion of the quantified benefits in Employee Safety and the Culture Index directly benefit electric customers. By allocating 60% of these combined customer benefits, the Company calculates annual savings for electric customers as follows: $1,300,345 from Employee Safety, $1,997,809 from avoided turnover costs associated with the Culture Index. Additionally, the full customer benefit of approximately $110 million from Electric Reliability impacts all electric customers. This totals over $113 million in value specifically for electric customers, far exceeding the total costs of the EICP allocated to electric customers.

Q. Why did you use a 60% allocation to evaluate benefits to electric customers?

A. The 60% allocation reflects the share of Consumers Energy customers who are electric customers. Allocating benefits by customer count is a reasonable method since the Employee Safety and Culture Index goal benefits apply Company-wide rather than to a single business line, consistent with standard cost allocation practices.

Q. Should the Company be pursuing these benefits independent of the EICP?

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in

business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that ensures employees are focused on delivering customer value through continuous improvement. Making it clear to employees that a portion of their market-based compensation is at risk and depends upon their collective ability to meet these targets emphasizes the importance of goal achievement and encourages coworkers to deliver their best performance.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. Yes. I believe the design of the EICP is intended to and does make it significantly more likely customer benefits will be achieved by establishing operational goals to improve the Company's ability to continuously improve the delivery of customer value through safe, reliable, affordable, and clean energy services. By placing a portion of employees' market based compensation at-risk, employees are incentivized to meet the EICP operational goals.

Q. Are you confident the Company can consistently achieve 100% targets on the EICP operational goals?

A. Yes. Over the past four years, the Company and its employees have, on average, slightly exceeded the 100% targets of the EICP operational goals. Refer to Exhibit A-70 (AMC-1) for EICP Operational Performance Metrics for the operational goals and targets.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics included in the EICP are designed to complement, rather than duplicate, each other. Each metric targets a distinct operational or cultural outcome that collectively supports the Company's commitment to safety, reliability, and culture.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. I am currently the Manager, Benefits.

Q. What are your responsibilities as Manager, Benefits?

A. I am responsible for the design, implementation, and administration of the Company's retirement and health care plans, and our department oversees the benefit plans for employees and retirees. In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities include designing, reviewing, and administering competitive, cost-effective, quality plans that attract and retain qualified employees to serve customers. These plans aim to provide a portion of an employee's retirement income, along with social security benefits and personal savings.

In the benefits area, the Company contributes to the cost of health care plans (medical, prescription drug, dental, including Health Savings Accounts ("HSAs") and Health Care Flexible Spending Accounts ("HCFSAs")), life insurance, and Long-Term Disability ("LTD") insurance. Our department also designs, reviews, and administers these health care and other benefit plans to ensure they are competitive, cost-effective, and of high quality for employees and retirees, helping to attract and retain qualified employees to serve customers. Additionally, the Company offers several benefit plans at group

discounted rates, requiring employees to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. In 2024, the Company added hospital indemnity, critical illness, and accident benefits. In 2026, the Company added Identity Theft and Legal Plan Services as new voluntary programs. These insurance plans help attract and retain qualified employees by protecting them and their families from significant financial loss in various areas. Our team is also responsible for Absence Management, Workers' Compensation, and Occupational Health programs, as well as the total well-being program, Live Well 365, which motivates employees to manage their overall well-being.

Q. What is your formal educational experience?

A. In 1998, I graduated from Siena Heights University in Adrian, Michigan with a Bachelor of Business Administration degree. I hold a Professional certification in Human Resources from HR Certificate Institute ("HRCI") and the Society of Human Resource Management ("SHRM").

Q. Would you please describe your previous work experience?

A. In 1995, I began my career focused on human resources at Health Care Solutions, Inc. as a Human Resources Manager ("HR"). In this role, I was responsible for the HR Management of the corporate office in Ann Arbor, MI. Also, I had leadership responsibility over all field HR Managers. In addition to this responsibility, I managed all health care and retirement plans for the company. It was my sole responsibility to ensure employees were enrolled in the correct plans and provide any administration to the plan. This also included plan audits and decision making in determining the best vendors.

In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits Specialist. My area of responsibility was retirement plans, disability, and life insurance plans. In this role, I was responsible for the relationship with vendors and the administration of plans for our employees. I was the primary vendor contact for these areas and was heavily involved in all Request for Proposal processes in choosing vendors. While in this position, I sat on the Retirement Committee as the Secretary and took part in plan design and fund selections for both the pension and the savings plan.

In 2020, I joined Consumers Energy as Manager, Retirement Plans. My responsibilities included complete oversight for the Company pension and savings plans (401k). In this role, I ensured the Company provides retirement benefits to active and retired employees while maintaining accurate legal compliance with the Internal Revenue Service.

In March 2024, I was promoted to Senior Manager, Benefits. In this role I continued complete oversight for the Company pension and savings plans (401k) with the addition of assuming responsibility for health and welfare benefits.

In December 2025, our department was realigned which resulted in my position changing to Manager, Benefits focusing on Retirement plans and Voluntary benefits. Health and Welfare benefits transitioned to another member of our team.

Q. Are you a member of any professional societies or trade associations?

A. I am professionally certified as a HR Professional through both SHRM and HRCI.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for the Company's costs related to the electric business portion of retirement, health care, life insurance, LTD plans, and

other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address health care, life insurance, LTD plans, and other benefits, which include absence management and educational assistance programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-125 (KKG-1)	Summary of Actual and Projected Benefits O&M Expenses for the Year 2025 and Test Year Twelve Months Ending April 30, 2028;
Exhibit A-126 (KKG-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-127 (KKG-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-128 (KKG-4)	CMS Energy – Actuarial Letter of Support for 2026 Year Projections.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-125 (KKG-1).

A. Exhibit A-125 (KKG-1), page 1, summarizes 2025 actual expenses through the 12 months ending April 30, 2028, projected electric Operating and Maintenance ("O&M") expenses for the Company's retirement and insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the actual expense in 2025 for each plan. Column (c) provides the projected expense for the 12 months ending April 30, 2028. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in

this testimony and included in column (d). Column (e) is the projected test year O&M expense and is the sum of columns (b) + (c) + (d).

Q. Please describe Exhibits A-126 (KKG-2), A-127 (KKG-3), and Confidential Exhibit A-128 (KKG-4).

A. Exhibits A-126 (KKG-2) and A-127 (KKG-3) provide the Aon actuarial projections for Pension and Other Post Employment Benefit ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are from the year-end 2025 measurement of the Pension and OPEB plans and with current market conditions as of December 31, 2025. A letter from the actuary regarding the accuracy and completeness of the projections, including several key assumptions used in the projections, is included in Confidential Exhibit A-128 (KKG-4).

I. RETIREMENT BENEFITS PLANS

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-125 (KKG-1), page 1, lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the electric portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars charged to electric operations compared to the labor dollars charged to both electric and gas operations. These allocation studies are performed by the Accounting Department. The electric portion of the O&M expense for these plans is shown on Exhibit A-125 (KKG-1), page 1.

Pension Plans

Q. Would you please explain your Exhibit A-125 (KKG-1), line 1, which begins with ($47,918,000) in 2025?

A. Exhibit A-125 (KKG-1), page 1, line 1, shows the actual 2025 pension expense and the projected expense for 12 months ending April 30, 2028, attributable to the electric portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715, formerly known as Financial Accounting Standards ("FAS") 106. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this electric rate case, the Pension Plans were measured in January for year-end December 31, 2025.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the annual pension expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service costs or credits, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on their specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. There is also an assumption made for the expected return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary, the plan's investment advisor, and the Company, and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and plan design changes that would be amortized are included as a part of this component of plan expense. The amortization can be either credits or costs.

To calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses several assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

Q. Please describe how the discount rate is set each year.

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on the most current market conditions.

Q. Please describe how the expected return on plan assets is set each year.

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case?

A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07 standard allows only the service cost component of each expense to be recorded as an operating expense and all other benefit-cost components are to be recorded outside operating income. The Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

Q. Please describe the development of the Pension Plans' expense shown on Exhibit A-125 (KKG-1), page 1, line 1, which begins with ($47,918,000) for 2025.

A. The annual pension expense shown on Exhibit A-125 (KKG-1), page 1, line 1, for the electric utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual electric utility O&M expense for Pension of ($47,918,000) in 2025, and projected expense of ($61,852,000) for the 12 months ending April 30, 2028. Exhibit A-125 (KKG-1), page 2, line 1, column (e), compares Aon's projected test year expense with the 2025 actual expense to calculate other adjustments.

Q. Have there been any significant plan design changes to the Pension Plan in recent years?

A. No. The last significant change was made on January 1, 2018. At that time, the Company split its Pension Plan into two plans. Generally, all participants who were employees of the Company on August 1, 2017, were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred because of this change. The Company decided to make this change to help manage expenses of the Pension Plans by extending the amortization period for the inactive group and enabling the mitigation of Pension Benefit Guarantee Corporation premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2025?

A. No, the Company did not contribute to either plan in 2025.

Q. Will the Company make any cash contributions to the Pension Plans in 2026?

A. No cash Pension Plan contributions are required in 2026 to avoid benefit restrictions. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

Q. Why did the pension expense decrease for the projected test year from 2025?

A. The Pension expense decreased due to higher-than-expected asset returns in 2025 and higher expected future returns.

Q. Have any changes recently been made to the Pension Plans' benefits?

A. Effective November 1, 2020, the Company changed the unreduced early retirement age from 62 to 61 for the Company's pension union eligible employees. This benefit enhancement allows for the Company to continue to retain current union pension eligible employees since they can now retire one year earlier but not lose any percentage of their pension benefit and was very well received. The additional changes in the projected pension expense estimates from 2025 to the 12 months ending April 30, 2028, are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

DB Pension/OPEB Volatility Mechanism

Q. Please describe the DB Pension/OPEB Volatility Mechanism ("VM") that the Company is proposing.

A. The Company requests the ability to continue its implementation of a DB Pension/OPEB VM, previously authorized by the Michigan Public Service Commission (the "Commission" or "MPSC") in Case Nos. U-21224, U-21389, U-21585, and U-21870. The sensitivity of DB Pension/OPEB VM expenses to changes in asset returns or other assumptions creates a significant potential for large variability in future expenses. Customers benefit from a mechanism that eliminates the risk of future volatility in expense. Without a mechanism, there could be substantial, unanticipated swings in the DB Pension/OPEB expense. The proposed mechanism, which mirrors the mechanism that has existed since 2023, would protect customers from this volatility by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715.

Q. Is the mechanism symmetrical?

A. Yes. Under the mechanism, if the actual annual DB Pension/OPEB expense is less than the expense approved in rates, the difference would be recognized as a regulatory liability and amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the difference would be recognized as a regulatory asset and amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. The mechanism is not only fair but similar mechanisms have been approved by the Commission

for other utilities in contested cases. See, e.g., MPSC Case No. U-21297, December 1, 2023 Order, pages 222-224; MPSC Case No. U-21291, November 7, 2024 Order, page 161.

Q. Please describe the Pension VM Deferral on Exhibit A-125 (KKG-1), page 1, line 7, column (b), which begins with ($3,016,000) for 2025.

A. Per Case No. U-21389, the Company was authorized to defer actual DB Pension expense different than the approved annual amount of ($43,327,000) starting March 2024. In Case No. U-21585, the Company was again authorized to defer the actual DB Pension expense different than the approved annual amount of ($53,469,000) starting in April 2025. In 2025, the actual DB Pension expense of ($47,918,000), as shown on Exhibit A-125 (KKG-1), page 1, line 1, column (b), was higher than approved amounts for 2025. The Company calculated the authorized amount for three months of 2025, totaling ($10,832,000), by taking the annual authorized amount in Case No. U-21389 of ($43,327,000), dividing it by 12, and multiplying by three months for January to March 2025. For the months of April to December 2025, the Company calculated nine months of authorized expenses totaling ($40,102,000). This was calculated by taking the 12 months authorized amount in Case No. U-21585 ($53,469,000), dividing it by 12, and multiplying by nine months. Adding the three-month authorized amount of ($10,832,000) to the nine-month amount of ($40,102,000) results in a total authorized amount for 2025 of ($50,934,000). The Company recorded the difference between the actual DB Pension expense of ($47,918,000) and the approved rate expense of ($50,934,000) as the Pension VM deferral for the year 2025. This Pension VM deferral of ($3,016,000) resulted in a decreased expense for 2025, and the Company consequently recorded a Pension VM regulatory asset of $3,016,000.

Q. Please describe the Pension VM Amortization on Exhibit A-125 (KKG-1), page 1, line 9, column (c), which begins with ($3,195,000) for 12 months ending April 30, 2028.

A. The Pension VM amortization includes deferred amounts being amortized from 2023 to 2027. These deferred Pension VM amounts are being amortized over a 10-year period, consistent with the approach used in Case Nos. U-21389, U-21585, and U-21870.

Q. Please describe the OPEB VM Deferral on Exhibit A-125 (KKG-1), page 1, line 8, column (b), which begins with $1,609,000 for 2025.

A. Per Case No. U-21389, the Company was authorized to defer actual OPEB expense different than the approved annual amount of ($39,608,000) starting March 2024. In Case No. U-21585 Order, the Company was authorized to defer actual DB Pension expense different than the approved annual amount of ($50,333,000) starting in April 2025. In 2025, the actual OPEB expense of ($49,261,000), as shown on Exhibit A-125 (KKG-1), page 1, line 5, column (b), was lower than the approved amounts for 2025. The Company calculated three months authorized of ($9,902,000) by taking the authorized amount in Case No. U-21389 of ($39,608,000), dividing by 12, and multiplying by three months for January to March 2025. For the months of April to December 2025, the Company compared nine months of authorized ($37,750,000) by taking the 12-month authorized amount in Case No. U-21585 of ($50,333,000), dividing by 12, and multiplying by nine months. Summing ($9,902,000) and ($37,750000) gives the total authorized amount for 2025 of ($47,652,000). The Company recorded the difference between the actual OPEB expense of ($49,261,000) and the approved rate expense of ($47,652,000) as the OPEB VM deferral for the year 2025. This OPEB VM deferral of $1,609,000 resulted in an

increased expense for 2025, and the Company consequently recorded an OPEB VM regulatory liability for $1,609,000.

Q. Please describe the OPEB VM Amortization on Exhibit A-125 (KKG-1), page 1, line 10, column (c), which begins with $665,000 for 12 months ending April 30, 2028?

A. The OPEB VM amortization includes the deferred amounts being amortized for the years 2023 to 2027. The deferred OPEB VM is being amortized over 10 years, which is consistent with the VM in Case Nos. U-21389, U-21585, and U-21870 operated.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?

A. To stay competitive by offering a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP. This change applied to all existing Cash Balance participants and newly hired employees starting from September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Employees hired between July 1, 2003, and August 31, 2005, who were covered under the Cash Balance version of the defined benefit DB Pension Plan, became participants in the DCCP as of September 1, 2005. Concurrently, additional pay credits under the Cash Balance version of the defined benefit DB Pension Plan were discontinued for this specific group of employees.

Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?

A. Similar to the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a limited group of participants. Over time, this group will gradually decrease until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution as a percentage of an employee's base pay to the ESP—the percentages vary with years of service as described below. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005, participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. No changes have been made to the DCCP since 2021. Effective January 2021, for the Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%) employer funded cash contribution based upon the union employee's service time with the Company. New union hires receive an 8% contribution, which increases to 9% when they have six years of service with the Company. When union employees reach 12 years of service, they receive a 10% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism. The increase in the union DCCP contributions was needed for the Company to remain competitive to attract qualified employees and retain talent that maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees provides better service for customers.

The Company's exempt and non-exempt employees will continue to receive the DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016, continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain your Exhibit A-125 (KKG-1), page 1, line 2, which begins with $16,512,000 in 2025?

A. Exhibit A-125 (KKG-1), page 1, line 2, represents the electric operations O&M expense related to the DCCP. The actual electric operations expense for this plan in 2025 was $16,512,000 as shown in column (b). Column (c) shows the projected electric DCCP expense of $17,582,000 for the 12 months ending April 30, 2028. DCCP costs are projected to increase using merit salary rate factors of 3.2% for 2025 through the 12 months ending April 30, 2028. If a DB Pension individual retires, the new person hired to replace their role is entered into the DCCP plan. For the projected years 2026 through the 12 months ending April 30, 2028, costs were split using 64% electric and 36% gas, with 54% capital on electric expenses.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is it correct to say that all new hire employees who started on September 1, 2005, and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

ESP

Q. Please explain briefly the ESP.

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers Energy. Prior to January 2022, the Company matched 100% of the employees' first 3% in contributions and 50% of the employees' next 2% in contributions to the ESP. Employee contributions beyond 4% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions, and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. Effective August 5, 2024, the Dearborn Industrial Generation Plant Union employees began receiving matching contributions of 100% for

employee contributions of up to 6% of the employees' salary per their negotiated contract. Effective June 1, 2025, union employees covered by the Operating Maintenance & Construction ("OM&C") contract began receiving matching contributions of 100% for employee contributions of up to 5%. Similarly, effective August 1, 2025, Virtual Call Center ("VCC") union employees began receiving matching contributions of 100% for employee contributions of up to 5% and effective October 1, 2025, union employees in the Zeeland Generation Plant began receiving matching contributions of 100% for employee contributions of up to 5%. All changes to the union match were tied to their respective contract renewal dates.

Q. Would you please explain your Exhibit A-125 (KKG-1), page 1, line 3, which begins with $13,321,000 in 2025?

A. Exhibit A-125 (KKG-1), page 1, line 3, represents the Company's electric operations expense related to the ESP. In 2025, the actual electric utility O&M expense for the ESP was $13,321,000. The electric utility's ESP O&M expense projected for the test year is $14,700,000. Savings Plan costs are projected to increase using merit salary rate type increase of 3.2% for 2025 through the 12 months ending April 30, 2028. For the projected years 2026 through the 12 months ending April 30, 2028, costs were split using 64% electric and 36% gas, with 54% capital on electric expenses.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to

employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable electric service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees benefits customers as much as, or more than, any investment in infrastructure.

Q. Is the ESP employer match discretionary?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with OM&C and VCC union employees assured these employees that the match would not be suspended during their five-year contract. This provision has remained in effect for all following contracts up to and including the most recent five-year contract negotiated in 2025.

With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefits package, and employees depend upon its continuation so they can accumulate savings for retirement. This is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, LTD plans, and other benefits of absence management and educational assistance, as well

as retiree health care and life insurance plans. These expenses are shown on Exhibit A-125 (KKG-1), page 1, lines 4 through 6.

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as FAS 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to electric O&M expense determined?

A. The portion of the Company's total program expenses attributable to the electric utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the electric utility to the total number of employees in both the electric and gas utility. The amount allocated to the electric utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula. For the projected years 2026 through the 12 months ending April 30, 2028, costs were split using 57% electric and 43% gas, with 54% capital on electric expenses.

Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-125 (KKG-1), page 1, line 4, which begins with $32,073,000.

A. Exhibit A-125 (KKG-1), page 1, line 4, contains electric operations O&M expenses for the -Company funded benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care. Life insurance and LTD make up a much smaller portion of the expense. In 2025, the Company incurred an actual combined expense of $32,073,000 for health care, life insurance, and LTD for electric operations. The projected electric operation expense for these benefits for the projected years 2026 through the 12 months ending April 30, 2028, is $36,558,000.

Q. What factors did you consider when projecting the test year's expenses for health care, life insurance, and LTD?

A. In projecting the test year's health care expenses, a number of factors were considered. The primary factors included current review of 2025 and 2026 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. Additional factors considered were the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the current employee headcount, and the continuing cost increase impacts of national health care reform.

Q. Please explain how these factors were used to determine the Company's expected health care costs.

A. The Company has determined that using the health care trend rate factors in this case will keep in line with expected costs. Exhibit A-125 (KKG-1), page 2, line 4, column (e), compares the projected test-year expense with the 2025 actual expense, adjusted for 2026, 2027, and 2028 health care trend rate, to calculate other adjustments. The amount shown in Exhibit A-125 (KKG-1), page 2, line 4, column (e) reflects the electric and gas split and capital percentage discussed above.

To further understand projected health care trends and costs, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan ("BC/BS") and Express Scripts. This analysis of the Company's health plans revealed that the Company's workforce is older than the average age of the population insured by the BC/BS and Express Scripts plans, and as a result, the Company's health plans have a higher expected utilization rate that is associated with an older covered population. Of the Company's current workforce, as of December 31, 2025, 47% of employees are over age 45; 32% are over age 50; and 18% are over age 55. The Company understands the older age of its workforce is expected to lead to a higher health care expense (primarily due to utilization of services).

To project future health care expenses, the Company and WTW also considered all the plan changes and programs that the Company has already implemented. These changes include sharing expected health care expense increases with employees through plan design

changes like increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the Consumer Directed Health Plan, a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2025 through 2030 contracts, as well as changes made to the employees' health care benefit plans in 2024 described in detail later in this direct testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that

lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?

A. There are a number of factors causing a higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, national health care reform will increase Company health care costs in the near term because of eligibility expansions (e.g. adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that healthcare costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated, both local and national health care costs continue to increase at rates greater than general CPI inflation.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-125 (KKG-1), page 1, line 4.

A. For 2026, the Company used inflation factors of 2.9%. In 2027, the Company used 2.5%, and for 2028, 2.2% was used. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 2.9%, 2.5%, and 2.2% annual increases represent the normal, expected merit increases in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company aggressively manages these benefit costs by analyzing costs and plan designs on an annual basis with a third-party vendor, WTW. An example of recent changes made to manage the cost of the Company's health care plans offered to employees and retirees follows:

- Negotiated administrative fees and insured plan premium rates annually.
- Implemented health and disease management programs and added case management.
- Effective January 1, 2024, the Company made a plan design change in the Salaried Active Medical plans so the out-of-pocket limits for both Union and Salaried employees are now the same. In addition, changes were made to decrease premiums in the Salaried Active Community Blue Medical for active employees.
- Eliminated eligibility for Salaried Retiree Life – Employer Paid for those who retired on/after January 1, 2024. They may still participate in Retiree Life, but at their own cost; and
- Effective January 1, 2025 current Salaried and Retirees (Exempt/Non-Exempt) who are under age 65 as of 1/1/2025 and Spouses, and Survivors under age 65 were moved to the Via Benefits Health Insurance Marketplace (also known as the Individual and Family Plan Marketplace) and will no longer be eligible for coverage in the Blue Cross Blue Shield of Michigan/Express Scripts and Delta Dental retiree group healthcare plans. Dependents under the age of 26 and disabled dependents will remain on current active coverage with BCBS of Michigan.

Retiree Health Care and Life Insurance

Q. Would you please explain your Exhibit A-125 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with ($49,261,000) in 2025?

A. Exhibit A-125 (KKG-1), page 1, line 5, reflects the actual 2025 and projected 12-month period ending April 30, 2028, electric utility retiree health care and life insurance expenses under ASC 715 (formerly known as FAS 106 expense). Each of the annual expense levels

shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined by using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate an account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this electric rate case, OPEB was measured in January for the year-end 2025.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 retiree health care and life insurance expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs or credits, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 retiree health care and life insurance expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method used to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

Q. Are actuarial and administrative expenses included in Exhibit A-125 (KKG-1), page 1, line 5?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-125 (KKG-1), page 1, line 5.

Q. What changes were made to the 2024 retiree health care plans?

A. In 2024, changes were made to decrease premiums in the Aetna Traditional Medical Plan for Retirees.

Q. What changes were made to the 2025 retiree health care plans?

A. Effective January 1, 2025, current Salaried and Retirees (Exempt/Non-Exempt) who are under age 65 as of January 1, 2025 and Spouses, Dependents, and Survivors under age 65 were moved to the Via Benefits Health Insurance Marketplace (also known as the Individual and Family Plan Marketplace) and will no longer be eligible for coverage in the Blue Cross Blue Shield of Michigan/Express Scripts and Delta Dental retiree group healthcare plans.

Q. What changes were made to the 2026 retiree health care plans?

A. In 2026, no changes were made to the retiree health care plans.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this electric rate case, the OPEB Plan was measured in January for year-end 2025.

Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company adopted the ASU No. 2017-07 as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-125 (KKG-1), line 5, which begins with ($49,261000) in 2025.

A. The retiree health care and life insurance O&M expense level shown on line 5 for the electric utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2025 retiree health care and life insurance O&M expense for the electric utility was ($49,261,000). The projected electric O&M retiree health care and life insurance expense is ($52,761,000) for the projected 12-month period ending April 30, 2028. Exhibit A-125 (KKG-1), page 2, line 5, column (e), compares the Aon actual calculation of expense with the 2025 actual expense to calculate other adjustments.

Q. Why did the retiree health care and life insurance expense decrease for the projected test year from 2025?

A. The retiree health care and life insurance expense decrease due to higher-than-expected asset returns in 2025.

Q. Would you please explain your Exhibit A-125 (KKG-1), page 1, line 6, for Other Benefits, which begins with $2,822,000 in 2025?

A. Exhibit A-125 (KKG-1), line 6, reflects the actual 2025 and projected 12-month period ending April 30, 2028 expenses for the electric utility benefits labor, the absence management program, the educational assistance program, and the employee assistance program. The adjustment in Exhibit A-125 (KKG-1), page 2, line 6, column (e), compares the projected test-year expense with the 2025 actual expense, adjusted for 2026, 2027, and 2028 inflation.

Q. Please explain why the absence management program is important to attract and retain employees.

A. Paid sick leave is needed to attract and retain employees. On January 2, 2026, the Company outsourced to an external consultant named Absence Plus to manage the Company's absence process. Absence Plus will be to improve the absence rate and provide a higher level of standardization, controls, and overall best practices to mitigate risk. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

Q. Please explain why the educational assistance program is important to attract and retain employees.

A. Educational assistance programs are widely available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company,

particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable electric service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees benefits customers as much as, or more than, any investment in infrastructure. Educational assistance is just such an investment. It provides the opportunity for employees to continue their education, which further improves their skills to serve the customers of the Company.

Q. Please explain why the employee assistance program is important to attract and retain employees.

A. The Company offers employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability to perform at work or in life. The employee assistance program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all the Company's employees and retirees.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

MICHAEL C. GRONDIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Michael C. Grondin, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Principal Rates Analyst in the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. I graduated from the University of Michigan in December 2008 with a Bachelor of Science in Engineering degree in Industrial & Operations Engineering. I started my career in 2009 with Jacobs Engineering as an Operations Research Analyst, developing models and conducting analyses for Department of Defense contracts. In 2015, I became an Optimization Analyst at Domino's, conducting analyses on digital ordering channels, the rewards program, and a pilot program. In 2017, I became a Senior Engineer II at Consumers Energy within the Electric Supply organization supporting the development of short-term load and Locational Marginal Price ("LMP") forecasting models and related analyses regarding model accuracy as well as post-event analytics associated with the Company's Residential Demand Response ("DR") programs. In January 2020, I added Midcontinent Independent System Operator, Inc. ("MISO") market administration and analytics of all DR programs for the Company's Commercial and Industrial ("C&I") customers, including working with the Company's interruptible service customers and energy intensive rate customers on matters pertaining to DR policy, administration, and regulatory compliance. In 2022, I took over responsibility for the long-term outage coordination and annual MISO Generator Verification Test Capacity submittal for the

Company's generating sites. In March 2025, I departed the Electric Supply organization as a Senior Data Engineer and joined the Rates and Regulation Department as a Principal Rates Analyst.

Q. What are your responsibilities as a Principal Rates Analyst for Consumers Energy?

A. In my current role I contribute toward the development of the Company's cost of service study ("COSS"), load research, rate design, and other rate-related analyses.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-20766	DR Reconciliation;
Case No. U-21080	DR Reconciliation;
Case No. U-21233	DR Reconciliation; and
Case No. U-21593	PSCR Reconciliation.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present the Company's proposed rate design that will result in electric revenues sufficient to collect the total revenue requirement proposed by the Company in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-16 (MCG-1)	Schedule F-2.0	Summary of Present and Proposed Revenues by Rate Schedule;
Exhibit A-16 (MCG-2)	Schedule F-2.1	Calculation of Rate Design Targets;
Exhibit A-16 (MCG-3)	Schedule F-3.0	Present and Proposed Revenue Detail;
Exhibit A-16 (MCG-4)	Schedule F-4.0	Comparison of Present and Proposed Monthly Bills;

Exhibit A-129 (MCG-5)	Electric Rate Case (ERC) Deferral Surcharge;
Exhibit A-130 (MCG-6)	Investment Recovery Mechanism (IRM) Surcharge;
Exhibit A-131 (MCG-7)	Present and Proposed Revenue Detail for General Secondary Electric Heating;
Confidential Exhibit A-132 (MCG-8)	Long-Term Industrial Load Retention Rate (LTILRR) Revenues; and
Confidential Exhibit A-133 (MCG-9)	Large Economic Development Rate (LEDR) Revenues.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. RATE DESIGN OVERVIEW

II. RATE DESIGN PROPOSALS

III. SURCHARGES

I. RATE DESIGN OVERVIEW

Q. Please describe the primary objectives of rate design.

A. Consistent with the rate designs approved in prior cases, I used the following four key objectives to inform my rate design in this case. My first objective was to adhere to the cost of service in accordance with the requirements set forth in MCL 460.11. I did deviate from the COSS in a couple of instances and will further elaborate on my rationale for doing so later. My second objective was to design rates that encourage the efficient use of the Company's electric system. This means setting rates that accurately reflect the type of cost (fixed versus variable) as well as the temporal nature of certain costs, such as the increased cost of providing energy during peak seasons and times of day. My third objective was to

design rates that promote a favorable business climate. My fourth objective was to design stable rates that provide the Company with a fair opportunity to collect its revenue requirement.

Q. Please describe the cost of service requirements set forth in MCL 460.11.

A. MCL 460.11 requires electric utilities to design rates that reflect the cost of providing service to each customer class. In other words, costs assigned to one class cannot be reassigned to another without cost justification. The intent of this being to prevent, or at the very least limit, interclass subsidies. However, this does not completely remove the utility's ability to maintain crossing-points between rates within a class and to make other adjustments to deviate from the COSS in some instances. I have identified these deviations as adjustments to the class COSS in Exhibit A-16 (MCG-2), Schedule F-2.1.

Q. Please describe your reasons for making these adjustments.

A. Consistent with prior electric rate cases, I am recommending six adjustments to the assignment of costs across the various rate classes and schedules as part of rate design. The first standard adjustment, shown on line 3 of Exhibit A-16 (MCG-2), Schedule F-2.1, reflects the difference between the market cost of production capacity collected from large standby customers taking service under Rate GSG-2 and the embedded cost of capacity allocated to them in the COSS. Two similar adjustments—the second and third—are made for both production energy and transmission costs, shown on lines 7 and 13, respectively. In total, these three adjustments suggest that large standby customers pay less under the market-based rate design structure for production and transmission standby service than they would under an embedded cost of service design.

The fourth standard adjustment, shown on line 18, is used to correct for an over allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS. In the 2019 electric rate case, Case No. U-20134, it was brought to the Company's attention that it was inadvertently over allocating substation costs to the higher voltage level rates by excluding customer-owned substations from its COSS. To remedy this issue, the Company agreed to reassign the portion of substation costs by allocating those costs to customers who owned their substation in the COSS as part of rate design. The easiest way to accomplish this was to allocate the substation ownership credits across the rate classes based on the distribution allocators developed in the COSS.

The fifth adjustment, shown on line 19, reflects the life line credits (senior citizen and low-income) that have traditionally been supported by all customer classes. Unlike the other approved adjustments, however, the life line adjustment is not cost justifiable. Instead, it is based on the Commission's authority to approve special senior citizen and low-income rates granted under MCL 460.11.

The sixth adjustment, shown on line 2, reflects the reallocation of DR credits recovered through base rates to reflect the reduced capacity requirements associated with these programs.

Q. Please explain your approach in designing rates to collect the Company's production costs.

A. Production is comprised of both fixed and variable costs, which are separated in the COSS between capacity and energy costs. Production capacity represents the cost of a generating plant and having it stand ready to serve customer demand over an extended period of time (annually) or at a certain hour (peak). Conversely, production energy represents the cost

of running these plants and is usually attributed to fuel expenses. Traditionally, the Company has used a combination of historical prices based on the MISO market to estimate the energy price spread of providing service during different time periods.

Q. Are you recommending any changes to the methodology used to calculate the production energy price spreads as part of the rate design?

A. No. Consistent with the method used in the prior electric rate case, Case No. U-21870, the Company is using the weighted average hourly LMP to calculate the energy charge spreads for the various Time-of-Use ("TOU") rates. This weighting of hourly LMP values based on the corresponding hourly energy use better reflects the value of energy in each time period.

Q. Please describe the calculation of the Long-Term Industrial Load Retention Rate ("LTILRR") revenues shown in your Confidential Exhibit A-132 (MCG-8).

A. The first page of Confidential Exhibit A-132 (MCG-8) contains the forecasted test year billing determinants and monthly charges based on the approved LTILRR tariff and customer contract. The second page of Confidential Exhibit A-132 (MCG-8) calculates the test year miscellaneous revenues, provided to Company witness Eugène M. Breuring, based on the information from the first page and the forecasted production and transmission costs sponsored by Company witness Joshua W. Hahn.

Q. What happens if actual LTILRR electric sales are less than the level forecasted by the Company in this case?

A. Any changes in the electric sales and power supply costs associated with the LTILRR are included in the Company's annual PSCR plans and reconciliations. For example, if the actual LTILRR electric sales are lower than the levels forecasted in this case, then the

Company would include the lower power supply miscellaneous revenue as part of the LTILRR payment in its PSCR reconciliation. Similarly, a higher sales level would result in a higher payment in the PSCR reconciliation.

Q. Is the Company recommending any changes to the LTILRR in this case?

A. No, it is not.

Q. Please describe the calculation of the Large Economic Development Rate ("LEDR") revenues shown in your Confidential Exhibit A-133 (MCG-9).

A. In Case No. U-21160, the MPSC approved the LEDR tariff and inclusion of the related LEDR revenues in general rate cases as miscellaneous revenue. Confidential Exhibit A-133 (MCG-9) contains the forecasted test year billing determinants and monthly charges based on the approved LEDR tariff and forecasted customer usage during the test year. The calculated LEDR revenues are picked up by Company witness Breuring as part of total miscellaneous revenue in Exhibit A-15 (EMB-3), Schedule E-2.

Q. Is the Company proposing any changes to LEDR in this case?

A. Yes. The change to LEDR is discussed below.

II. RATE DESIGN PROPOSALS

A. Residential

Q. Please explain your approach in designing the Company's current residential customer class rates.

A. The Company is recommending the Commission maintain the currently approved residential rate design structure. My overall objective in designing the residential rates was to continue providing a sense of stability for this class by maintaining the existing rate structures for each option—i.e. Residential Summer On-Peak Basic Rate ("RSP"),

Residential Smart Hours Rate ("RSH"), Residential Nighttime Savers Rate ("RPM"), and Residential Service Secondary Non-Transmitting Meter Rate ("RSM"). There are no changes proposed to the structure or type of charges for RSP, RSH, RPM, and RSM. Also, the collection of charges within the available rate options were evaluated based on how each fit individually and collectively within the class. For example, the summer on-peak charges assessed in all three residential TOU options were set equal since each covered the same period and are intended to inform customers about the cost of providing power during that period.

Q. What is the monthly residential bill impact under your proposed rate design?

A. The average monthly residential customer bill is projected to increase 9% from approximately $142 per month to $155 per month. The monthly customer typical bill impacts for each rate schedule are also shown in Exhibit A-16 (MCG-4), Schedule F-4.0.

Q. How does the residential monthly bill under your proposed rate design compare with the national average bill projected by the Energy Information Administration ("EIA")?

A. The national average residential electric bill from the EIA is projected to be $161 per month in 2027, which is approximately $6 more than the $155 per month projected for the Company's customers. The Company also offers customers various payment plans and ways to reduce their energy bills through its residential assistance, energy efficiency, and DR programs. In addition, customers interested in proactively managing their energy bills can use many of the programs and digital tools the Company provides; including the online energy dashboard and billing detail to understand how energy is used throughout the day, tips for reducing energy waste, bill forecast trends, and the rate advisor tool to identify

actions that can be taken to reduce their bills. In addition, the Company is proposing an increase to the monthly Residential Income Assistance credit as discussed by Company witness Heidi J. Myers.

Q. Is the Company proposing any additions to the current Residential rate structure?

A. Yes. The Final Order in Case No. U-21870 ("Order") directed the Company to propose an electric heating rate in its next case. As such, the Company has designed a Residential Electric Heating ("REH") rate, which is reflected in Exhibit A-16 (MCG-3), Schedule F-3.0, page 5.

Q. Please describe the Commission's Order requirements in Case No. U-21870 regarding the Company's proposal for a REH rate.

A. The Order stated that the Company shall propose an electric heat/heat pump rate in its next rate case, hold a collaborative workgroup meeting to solicit input beforehand, and consider the following when developing the rate: (1) options for both seasonal and temporal differentiation; (2) EH/heat pump rates for residential and non-residential customers; (3) tradeoffs between rate designs focused on electric heating in general and those focused on technologies such as prompting heat pumps; (4) tradeoffs relating to eligibility requirements and verification (e.g., self-attestation, consumption analysis, submetering); and (5) delivery of the new rate, including strategies and tools for customer and contractor education, such as rate impact calculators and opt-out design strategies. The Commission also stated that consideration should be given to the additional system-wide benefit that heat pumps can provide, including the ability for DR or other broader system support.

Q. Please describe the Company's proposed method for creating the REH rate structure.

A. The Company held a collaborative workgroup meeting to solicit input on the REH rate structure with multiple considerations. Based on workgroup feedback and customer data availability, the Company is proposing a winter declining block rate structure where the first block is the first 750 kWh of usage and the second block is any usage above 750 kWh during the billing month. The summer rate structure will remain the same as RSP.

The proposed winter REH rate design is structured to address electric heating customers by aligning lower marginal winter prices with usage levels that are indicative of space-heating load. Analysis of customer usage shows that consumption materially above baseline residential levels during the winter season—represented by usage exceeding 750 kWh per month—is most reasonably attributed to electric heating rather than non-heating end uses. Accordingly, the two-block winter structure uses the first 750 kWh to reflect typical non-heating household usage, while pricing incremental usage above that level at a lower marginal rate consistent with winter market cost conditions.

Q. How was the winter declining block structure determined?

A. The winter declining block structure breakpoint was mathematically determined utilizing high-level consumption data. Based on billed electric consumption data and customer accounts for December, January, and February billing months spanning 2023 through 2026 period, it was determined that the average monthly electric consumption per contract account across the observed months was approximately 664 kWh per month. Considering variability in monthly average consumption, the standard deviation of monthly consumption per contract account was approximately 48 kWh. One standard deviation corresponded to a range of approximately 615 to 712 kWh per contract account per month.

Using rounding as a natural breakpoint, the initial block was set to the first 750 kWh of usage, and the second block was set to any usage above 750 kWh.

Q. How were the REH rates developed?

A. The Company did not attempt to project REH-related determinants or impute a load profile based on a certain subset of customers. Rather, the REH rates were developed using the existing Rate RSP customer load profiles, and the rate design reflects a break even relative to the RSP rate, i.e. the rates result in the same level of revenue recovery absent any load shifting by the customer.

Winter REH rates were developed using LMP differentials and applied directly in Exhibit A-16 (MCG-3), Schedule F-3.0, page 5, ensuring the rates are market-reflective. Average winter and summer LMPs were used to derive winter-to-summer ratios that quantify seasonal differences in marginal energy, capacity, and transmission costs, which show that costs are materially lower in the winter heating season. These LMP-based differentials were applied to set winter-only REH production rates, including a two-block structure for the first 750 kWh of baseline heating usage and excess winter consumption. Non-capacity energy, capacity, and transmission components were each derived using the applicable LMP differentials, resulting in lower marginal pricing for incremental winter usage consistent with market signals. Summer REH rates remain unchanged, are not tiered, and tie directly to Summer RSP rates; only winter rates reflect the LMP-based block structure. Overall, this approach ensures winter REH rates accurately reflect seasonal market conditions, price incremental usage at marginal cost, and remain transparent and aligned with cost causation principles.

Q. How did the Company evaluate the points considered in the Order?

A. In developing the proposed REH rate design, the Company evaluated multiple factors identified by the Commission, including seasonal and temporal differentiation, customer class treatment, technology neutrality, eligibility and verification, and delivery considerations. The Company prioritized seasonal differentiation to reflect winter heating cost characteristics while avoiding additional temporal complexity. The design remains technology-neutral, supporting heat-pump adoption through favorable winter price signals without imposing technology-specific eligibility or verification requirements. To encourage participation and limit any potential administrative burden, the Company avoided verification mechanisms and instead relied on rate structure and usage patterns. Regarding delivery considerations, the Company prioritized using clear rate differentiation to RSP and opt-in strategies to support customer understanding, minimizing confusion to enrollment, and preserving customer choice. These strategies support informed customer adoption. While not explicitly included in the initial rate design, the proposed design preserves the optionality for future DR integration and broader system support.

The Company recommends this initial REH rate design and will continue to collaborate with stakeholders on advancing and improving the rate over time. Additionally, the Company recommends a minimum six-month delay in implementing the REH rate to coincide no earlier than the implementation date of the SAP S/4HANA project, as discussed in testimony of Company witness Stacy H. Baker.

B. Secondary

Q. Is the Company proposing any changes to the Secondary rate structure?

A. No, the Company is proposing to maintain its current rate structure for secondary customers. However, the Order in Case No. U-21870 directed the Company to consider electric heating rates for residential and non-residential customers. Therefore, the Company is presenting a secondary winter declining block electric heating rate based on similar methodology as the residential electric heating rate. The secondary electric heating rate is presented in Exhibit A-131 (MCG-7).

Q. Please describe the development of the secondary electric heating rate.

A. Based on billed electric consumption data and contract accounts for December, January, and February billing months spanning 2023 through 2026 period, it was determined that the average monthly electric consumption per contract account across the observed months was approximately 1666 kWh per month with a standard deviation of approximately 65 kWh. One standard deviation corresponded to a range of approximately 1600 to 1731 kWh per contract account per month. Using rounding as a natural breakpoint, the initial block was set to the first 1750 kWh of usage, and the second block was set to any usage above 1750 kWh.

Q. Is the Company proposing to implement a secondary electric heat rate at this time?

No. The Company found that there is a broad range of electric consumption across secondary customers with limited insight into how much of this usage is associated with electric heating. Therefore, the Company has presented a secondary electric heat rate design but does not recommend implementing it at this time. The Company will continue to review and evaluate the viability of a secondary electric heating rate.

C. Primary

Q. Is the Company proposing any changes to the Primary rate structure?

A. The Company is not proposing any changes any changes to the rate structure for Primary Rates GP, GPD, GPTU, or EIP.

Q. Is the Company proposing any changes to LEDR?

A. Yes, the Company is proposing to update the production capacity charge based on the latest forecasted MISO Cost of New Entry ("CONE"). Additional compliance items related to LEDR are being addressed by Company witness Laura M. Connolly.

D. Lighting

Q. Is the Company proposing any change to the streetlighting rate structures?

A. No, the Company is proposing to maintain the current rate structure for the streetlighting rates.

E. Self-Generation

Q. Is the Company proposing any change to the Self-Generation rate structure?

A. No, the Company is proposing to maintain the current rate structure for Rate GSG-2.

III. SURCHARGES

Q. Please describe the method used to design the Electric Rate Case ("ERC") Deferral surcharge in this case.

A. As discussed by Company witness Patton, the Company is proposing an ERC Deferral surcharge to recover $25,008,000 of deferred distribution investments. Similar to the existing surcharge, the deferred costs were allocated to the various rates in Exhibit A-89 (EAD-5) and divided by the test year sales to calculate the surcharge.

Q. Describe the Investment Recovery Mechanism ("IRM") proposed by the Company.

A. The proposed IRM would authorize the Company to collect additional revenues associated with incremental distribution reliability spending beginning May 1, 2027 through April 30, 2029, with a distinct revenue amount to be collected in each 12-month period, as discussed in the testimony of Company witnesses Myers and Emily M. Duke.

Q. Please describe Exhibit A-130 (MCG-6).

A. Exhibit A-130 (MCG-6) is an illustrative calculation of the proposed IRM surcharge. It shows how the Company proposes to collect the revenue requirements associated with the IRM. The revenue requirements for each class are based on the cost allocation of the revenue requirements in Exhibit A-89 (EAD-5). The rate design for the various voltage levels for Rates GP, GPD, EIP, and GPTU are consistent with the rate differentials used in the Company's rate design. The surcharge is based on test year sales and would apply to both Full Service and Retail Open Access customers. With approval of the Commission, these rates would be effective for service rendered on and after May 1, 2027 and service on and after May 1, 2028. The IRM surcharges would continue until rates were modified in the Company's next electric case.

Q. How does the Company propose to reconcile the IRM?

A. As discussed in the testimony of Company witness Myers, the reconciliation of the IRM would be handled in a separate contested proceeding. The Company proposes to reconcile the IRM capital spend on an annual basis. The reconciliation would compare the Company's annual IRM revenue requirement based on the actual incremental investments for that 12-month period against the associated revenue requirement collected from customers by class for that year through the IRM surcharge. If, for example, the actual

IRM revenue requirement fell short of the Commission-approved amount collected through the surcharge, then the Company would refund customers the difference.

Q. Would the Company be allowed to increase the surcharges over the amount the Commission approved in a final order in this case?

A. No. The Company would only be authorized to implement the surcharges approved by the Commission in this proceeding. However, the Company would implement reductions as ordered by the Commission to modify the surcharge if the amount of the investment was less than the total incremental investment proposed spend amount.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Quentin A. Guinn and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Capital Asset Strategy Manager.

Q. What are your responsibilities as Capital Asset Strategy Manager for Consumers Energy?

A. As Capital Asset Strategy Manager, I am responsible for providing support and direction for Facilities strategy development, compliance, resource planning, and regulatory proceedings. The Facilities execution plan ranges from activities related to electric operations to those involving corporate operational areas of Consumers Energy. Facilities' asset portfolio consists of over 75 buildings (see Exhibit A-136 (QAG-4)) and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, wind generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case strategy and execution, corporate policy administration, organizational vision, and resource planning for field execution.

Q. What is your formal educational experience?

A. I hold a bachelor's degree in economics from Yale University, located in New Haven, Connecticut, and a Juris Doctorate degree from Washington University, located in St. Louis, Missouri.

Q. Would you please describe your previous work experience?

A. In 1999, I started my career at Consumers Energy as a Contracts Analyst. In 2000, I began a series of changing roles, with increasing responsibility, from Contracts Supervisor to Director of Contract Services. In each successive role, I led teams of Contract Analysts and Contract Administrators who were responsible for a broad range of construction, maintenance, consulting, information technology, and engineering contracts. The responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work, negotiating agreements, and administering contracts. In 2013, I began work in a series of successive roles focused on data, analytics, performance, and work management culminating in my current role as Capital Asset Strategy Manager.

Q. What is the purpose and scope of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's costs related to the Electric business portion of Facility Operations. To that end, I will:

- Describe the Facilities and Shared Services function;
- Describe the methodology employed by Facility Operations ("Facilities") for evaluating the health of its various facilities;
- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical year ended December 31, 2025, the bridge period beginning January 1, 2026 and ending April 30, 2027, and the projected test year ending April 30, 2028;
- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities and Shared Services for the historical year ended December 31, 2025, the bridge period beginning January 1, 2026 and ending April 30, 2027, and the projected test year ending April 30, 2028;

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or "the Commission")?

A. Yes. I have provided testimony on behalf of Consumers Energy in Case Nos. U-21148, U-21224, U-21308, U-21389, U-21490, U-21585, U-21806, U-21870, and U-21981.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (QAG-1)	Schedule B-5.4	Summary of Actual & Projected Capital Expenditures Facilities & Shared Services;
Exhibit A-134 (QAG-2)		Summary of Actual and Projected O&M Expenses Facilities & Shared Services;
Exhibit A-135 (QAG-3)		Detailed List of Projected Electric Capital Expenditures Facilities & Shared Services;
Exhibit A-136 (QAG-4)		Asset Replacement List of Projects and Capital Expenditures;
Exhibit A-137 (QAG-5)		New Construction List of Projects and Capital Expenditures; and
Exhibit A-138 (QAG-6)		Renovations List of Projects and Capital Expenditures.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (QAG-1), Schedule B-5.4, details the actual and projected capital expenditures related to Facilities and Shared Services for the calendar year 2025, bridge period (16 months ending April 30, 2027), and the projected test year 12 months ending April 30, 2028. Exhibit A-134 (QAG-2) details the O&M costs related to Facilities and

Shared Services. Exhibit A-135 (QAG-3) identifies Facilities and Shared Services projects and the projected capital expenditures related to those projects and programs. Exhibit A-136 (QAG-4) identifies Asset Replacement projects and the projected capital expenditures and project plans related to those projects and programs. Exhibit A-137 (QAG-5) identifies New Construction projects and the projected capital expenditures and project plans related to those projects and programs. Exhibit A-138 (QAG-6) identifies Renovations projects and the projected capital expenditures and project plans related to those projects and programs.

Q. Please explain the Facilities and Shared Services function.

A. The Facilities and Shared Services function consists of the following support organizations: Fleet Services, Facilities, Real Estate, Contractor Oversight, and Supply Chain Materials Management. Facilities and Shared Services acquires, constructs, and maintains assets required to support the functional areas of the business that serve the Company's customers.

Q. Are you addressing all support organizations related to Facilities and Shared Services in your direct testimony and exhibits?

A. No. Fleet Services will be addressed in the testimony of Company witness Joshua J. Judy.

Q. What is the function of the Facilities organization?

A. Within Facilities and Shared Services, Facilities manages, maintains, and operates over 75 buildings comprising 3.2 million square feet of building space across the state of Michigan that allows the Company to serve customers across the state in an efficient and effective manner.

Q. How have Company facilities changed over time?

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Of its over 75 buildings, nearly half were built or acquired during this period and remain in operation today. As a result, these buildings are now over 50 years old. The Company made no significant investment in its facilities and initiated no major renovations or construction of new buildings between 1970 and 2000 given competing customer investment priorities. In 2003, the Company constructed its One Energy Plaza headquarters building in Jackson. This construction marked the adoption of the open office concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was adopted to foster a more collaborative work environment. Between 2000 and 2016, the Company also closed many facilities including 22 service centers across Michigan to adapt to shifting population trends in the state and to reduce costs for customers.

Q. What structural concerns or problems do these aging structures and facilities create for the Company?

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in some facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not always cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is also increasingly difficult to identify and obtain adequate parts and to further locate the necessary expertise to work on aging equipment. In addition, these facilities were not designed to meet modern standards of energy

efficiency. As building code requirements evolve, the Company is required to initiate renovations and/or other facility improvements to remain code compliant.

Q. What concerns or problems do these aging structures and facilities create for the Company's customers?

A. The population and infrastructure of the state of Michigan look much different than they did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with growth focused in urban areas. The state's current population is now approximately 10 million, with much of the growth since the 1960s having occurred in suburban areas. The locations of some of the Company's facilities no longer allow the Company to optimize service to customers. In these situations, longer response times, increased drive times, and diminished ability to safely and efficiently store and deliver materials in support of electric reliability work make meeting service delivery standards difficult for the Company's employees who are dedicated to providing the best service to Consumers Energy's customers. The cost implications of these issues include but are not limited to higher transportation fuel costs, accelerated wear and tear on vehicles, and reduced cycle time for truck rolls - all of which increase service costs to customers. This issue is particularly pronounced at the Lansing Service Center, as I will discuss in detail later in my testimony.

Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?

A. The Company has been using a formal assessment process for several years that evaluates whether or not to invest in a facility by studying each facility's overall health beyond annual O&M expense. The Company plans to continue using this process and is enhancing it by incorporating the operational priorities of the Facilities organization's internal

business partners (e.g., Low Voltage Distribution, Gas Operations, etc.). Given the evolving nature of the workforce (i.e. with hybrid work), the Company is working to ensure its facilities are right sized and properly configured for the needs of the work.

Q. What is the formal assessment process related to facility health?

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The assessment process is periodically re-evaluated resulting in minor updates to the methodology to reduce subjectivity in scoring. The most recent assessment was completed in 2022. The Facilities Department consists of qualified, trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a score of 0 lowest to 5 highest per category), and then the facility is ranked on a multi-category scale (with an 80-point maximum score).

Q. What categories are included in the evaluation process of the Company's facilities?

A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as workplace efficiency, employee comfort, and talent attraction and retention); (iii) cost (such as facility operating costs, space optimization, and energy efficiency); (iv) delivery (such as response times, driving distance within service territory, and sustainability of operations); and (v) morale (such as employee pride, wellness, and retention).

Q. How is the quality of each category identified above established?

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score above 64 is designated as "Good"; a score of 48 to 64 is designated as "Serviceable," meaning that investment and/or replacement is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility. Facilities designated as "Poor" are typically candidates for replacement.

Q. What is the next step in the facility assessment?

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking and adjust the prioritization to reflect forecasted needs of the business. The Facilities team finalizes the score, and any facility that scores below a minimum acceptable level, 48 out of 80 points, may be a candidate for renovation or replacement.

Q. How does the Facilities organization consider the business needs of its internal business partners when selecting locations to target and how do facility health assessments and evaluations of business partner needs combine to create a prioritization plan for Facilities work?

A. The Facilities organization considers business partner needs by meeting on a regular basis with these organizations to review their business plans and the resulting impacts on the facilities necessary to support these plans. The process begins with a 10 Year Long Term Facilities Plan. This plan is maintained by the Facilities organization and contains fundamental information about each facility such as the year the building was constructed, estimated years of useful life remaining in the building, dates of major milestones in the life of the building (e.g. significant renovations and building additions), etc. The 10 Year

Long Term Facilities Plan is one of several inputs then used to inform creation of the Long Term Financial Plan ("LTFP"). The LTFP is a five-year financial plan created in part from the aforementioned facility health assessments. Facilities organization engineers and other technical experts across the Company (e.g. environmental analysts) generate health assessments and develop capital investment priorities based on the health assessments (e.g. replacement of specific assets at specific buildings, preventive maintenance of specific building systems, work on a building envelope). These capital investment priorities are then reviewed by business partners for alignment with their plans and can become projects incorporated into the LTFP. The ultimate list of capital investment projects incorporated into the LTFP is then derived from this collaboration between the Facilities organization and business partners. While considerable engineering rigor is applied to developing the facility health assessments, business partner priorities do affect the ultimate list of projects incorporated into the LTFP. The Kalamazoo Service Center Project included in this rate case, for instance, was elevated in priority to address negative employee morale and hazardous material issues, among other factors, that resulted in nearly 40% of the Kalamazoo Service Center being closed to employees.

Q. Does this process ensure priority is given to Facilities projects critical to ensuring the Company can serve its customers?

A. Yes. The facility health assessments and aforementioned planning process produce a prioritized list of facilities for renovation or replacement that is aligned with both the need to preserve and maintain facilities assets and support business plans in providing optimal customer service. Buildings that are in poor shape or are otherwise suboptimal negatively impact the Company's ability to serve customers.

Q. Are there situations in which prioritization of projects might change even after development of the LTFP?

A. Yes. Though not typical, reprioritization of projects after establishment of the LTFP can occur. For example, several years ago the Company reprioritized development of a service center in Tawas to provide timely support to customers in the greater Tawas region and to reduce the workload impact on local first responders during response to emergency utility events. In another example, the Company revised its plans for the Kalamazoo Service Center Project included in this case. In this instance, after examining the impacts of the COVID pandemic on the workforce and changes the pandemic wrought in how work is performed, the Company revised its original plan to replace the Kalamazoo Service Center and instead decided to renovate portions of it as many of the building modifications originally proposed became more costly due to supply chain issues and were also deemed no longer necessary to support the post-COVID workforce.

Q. Is the Company taking steps to ensure its facilities are right-sized given changes in the working environment?

A. Yes. The Company continues to monitor use of its facilities in a post-COVID work environment. Following the pandemic, in 2023, the Company established expectations for in-person work for all employees at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce

Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

Capital Spending Overview

Q. What programs are included in the projected capital expenditures for Facilities?

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.4, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.4, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

Other Equipment

Q. What is included in the Other Equipment program?

A. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate tools and equipment; Supply Chain tools and equipment; and Facilities tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.4, the Company is projecting to spend $820,000 on Other Equipment in the bridge period and $563,000 on Other Equipment in the test year.

Q. Can you elaborate on what the various categories of Other Equipment spending represent?

A. Wellness Equipment consists primarily of equipment used by Operations personnel and others in the Company's fitness centers. Computer Equipment includes computers acquired for use by Facilities and Shared Services personnel outside of routine lifecycle

replacements. These include acquisitions of computer equipment obtained for a specialty use (e.g. a plotter) or replacement of computer equipment that fails prematurely for various reasons. Print Equipment consists of large copying and printing equipment for the Company's Mail Room. Real Estate Tools and Equipment consists primarily of survey equipment. Supply Chain Tools and Equipment consists of tools and equipment acquired for material storerooms such as shelving.

Q. How did the Company determine this level of investment for Other Equipment?

A. Investment levels for Other Equipment are established annually as part of the annual budget setting process. Levels of investment are set to meet identified needs of the business and are established at or below the five-year historical average spend for Other Equipment.

Q. What specific projects and related forecasted spend constitute the bridge period and test year for Other Equipment?

A. Specific projects that constitute the forecasted spend for Other Equipment are not known in advance. For this reason, the Company uses a five-year historical average to determine Other Equipment capital expenditures. The Commission has accepted this rationale and granted the Company recovery for Other Equipment in multiple prior rate cases including MPSC Case Nos. U-21870, U-21806, U-21585, U-21389, U-21224, and U-20963.

Emergent Repairs

Q. What capital expenditures are included in the Emergent Repairs portfolio category?

A. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. As shown in Exhibit A-135 (QAG-3), the Company is projecting to spend $2,619,000 in the bridge period and $1,631,000 in the test year on emergent repairs. The Company maintains data on the age, condition, and maintenance history of its major

building system assets. This data, in conjunction with historical spend, is used to forecast projected spending on unplanned corrective maintenance and break fix repair of assets.

Q. How did the Company determine the level of investment for Emergent Repairs?

A. Levels of investment for Emergent Repairs are established at or below the five-year historical average spend for Emergent Repairs.

Q. What specific projects and related forecasted spend constitute the bridge period and test year for Emergent Repairs?

A. Specific projects that constitute the forecasted spend for Emergent Repairs are unknowable in advance. For this reason, the Company uses a five-year historical average to determine Emergent Repairs capital expenditures. The Commission has accepted this rationale and granted the Company recovery for Emergent Repairs in multiple prior rate cases including MPSC Case Nos. U-21870, U-21806, U-21585, U-21389, U-21224, and U-20963.

Asset Replacement

Q. What capital expenditures are included in the Asset Replacements portfolio category?

A. The Asset Replacements portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings, and furniture. Exhibit A-135 (QAG-3) shows the Asset Replacement portfolio category broken down across the different types of work. As shown in Exhibit A-135 (QAG-3), the Company is projecting to spend $12,699,000 on Asset Replacements in the bridge period and $8,759,000 on Asset Replacements in the test year.

Q. How are Asset Replacement projects targeted?

A. Similar to the aforementioned facility health assessments, asset condition assessments are performed by Facilities engineers on a regular basis, along with input provided by external

industry professionals. These assessments are conducted in accordance with best practices in the industry. For example, for roofing assets, a portion of roof sections is inspected annually such that all roofs are inspected once every three years. The condition of each assessed asset is prioritized following standard industry-recognized methodologies. Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. How does the Company identify locations for Statewide Paving projects?

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

Q. How did the Company determine the amount of needed investment in Statewide Paving projects for the bridge period and the test year?

A. The total amount of needed investment in paving projects begins with the five-year historical average spend. Paving condition assessments are then used to determine how that spend is allocated. While investment in paving projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. What specific paving projects and related forecasted spend constitute the bridge period for Statewide Paving projects?

A. The specific paving projects and related forecasted spend that constitute the bridge period for Statewide Paving projects is detailed in A-136 (QAG-4).

Q. What specific paving projects and related forecasted spend constitute the test year for Statewide Paving projects?

A. The specific paving projects and related forecasted spend that constitute the test year for Statewide Paving projects is determined annually as part of the aforementioned LTFP planning process. While investment in paving projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for roofing projects?

A. The condition of roofing assets is evaluated on a rolling three-year basis with a visual inspection and detailed infrared inspection performed annually for 33% of Company sites. Roofing assets are prioritized for replacement based on the lowest assessed condition index score.

Q. How did the Company determine the amount of needed investment in roofing projects for the bridge period and the test year?

A. The total amount of needed investment in roofing projects begins with the five-year historical average spend. Roofing condition assessments are then used to determine how that spend is allocated. While investment in roofing projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. What specific Statewide Roofing projects and related forecasted spend constitute the bridge period for Statewide Roofing projects?

A. The specific roofing projects and related forecasted spend that constitute the bridge period for Statewide Roofing projects is detailed in A-136 (QAG-4).

Q. What specific paving projects and related forecasted spend constitute the test year for Statewide Roofing projects?

A. The specific roofing projects and related forecasted spend that constitute the test year for Statewide Roofing projects is determined annually as part of the aforementioned LTFP planning process. While investment in roofing projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for Mechanical/Electrical projects?

A. The condition of mechanical/electrical assets is evaluated by Facilities engineers for all Company sites. Based on the results of these evaluations, targeted maintenance work is performed on mechanical/electrical assets. Where the condition of mechanical/electrical assets is determined to be below an acceptable threshold for targeted repair or maintenance, the mechanical/electrical assets are prioritized for replacement based on the results of these evaluations.

Q. How did the Company determine the amount of needed investment in Mechanical/Electrical projects for the bridge period and test year?

A. The total amount of needed investment in Mechanical/Electrical projects begins with the five-year historical average spend. Mechanical/Electrical condition assessments are then used to determine how that spend is allocated. Long lead times on mechanical/electrical

equipment can occasionally affect the Company's ability to complete planned projects within the projected test year. Nevertheless, while investment in mechanical/electrical projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. What specific mechanical/electrical projects and related forecasted spend constitute the bridge period for Statewide Mechanical/Electrical projects?

A. The specific mechanical/electrical projects and related forecasted spend that constitute the bridge period for Statewide Mechanical/Electrical projects is detailed in A-136 (QAG-4).

Q. What specific mechanical/electrical projects and related forecasted spend constitute the test year for Statewide Mechanical/Electrical projects?

A. The specific mechanical/electrical projects and related forecasted spend that constitute the test year for Statewide Mechanical/Electrical projects is determined annually as part of the aforementioned LTFP planning process. While investment in mechanical/electrical projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. How does the Company identify locations for Statewide Elevator projects?

A. The condition of elevator assets for all Company sites are evaluated by outside consultants and subject matter experts. Elevator assets are prioritized for replacement based on the results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with an assessment score of 3 or below are targeted for modernization or replacement.

Q. How did the Company determine the amount of needed investment in Statewide Elevator projects for the bridge period and test year?

A. The total amount of needed investment in elevator projects begins with the five-year historical average spend. Elevator condition assessments are then used to determine how that spend is allocated. While investment in elevator projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. What specific elevator projects and related forecasted spend constitute the bridge period for Statewide Elevator projects?

A. The specific elevator projects and related forecasted spend that constitute the bridge period for Statewide Elevator projects is detailed in A-136 (QAG-4).

Q. How did the Company determine the level of investment for Furniture?

A. The total amount of needed investment in Furniture begins with the five-year historical average spend. Furniture replacement is determined based on business need. Subject matter experts evaluate business unit requirements and existing furniture. Where the existing furniture does not meet business unit requirements, the furniture is identified for replacement. While investment in Furniture may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

Q. What specific furniture projects and related forecasted spend constitute the bridge period and test year for Furniture projects?

A. Specific furniture projects that constitute the bridge period and test year for Furniture are not known in advance. For this reason, the Company begins with a five-year historical average to determine Furniture capital expenditures. The Commission has accepted this rationale and granted the Company recovery for Furniture in multiple prior rate cases including MPSC Case Nos. U-21870, U-21806, U-21585, U-21389, U-21224, and U-20963.

New Construction

Q. What capital expenditures are included in the New Construction portfolio category?

A. The New Construction portfolio category includes major projects to build new structures, either on existing Company property or on new properties the Company acquires. In accordance with the Order in Case No. U-21585, the Company in this case will not seek an allowance for its Hastings Service Center Project in the New Construction category. See Exhibit A-134 (QAG-3). The Company will seek an allowance for this project when it demonstrates substantial progress on the project. In this testimony, the Company will provide information concerning the Lansing Service Center Project and Hastings Service Center Project and the status of each project respectively.

Q. Does the Company consider environmental impacts when planning for new construction?

A. Yes. New buildings incorporate the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards (see usgbc.org/leed), with specific emphasis on reduced energy

consumption, sustainability, and reduced operating cost. In addition, many modern building codes now incorporate standards consistent with USGBC and LEED standards.

Q. Do these environmental building standards benefit the Company's customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5% maintenance cost reduction. Consumers Energy's recently constructed Coldwater Service Center was designed and built to these standards.

Q. Describe the Lansing Service Center project. What is its overall goal?

A. In this project, the Company has purchased land in a new location and will construct a new facility on that property. This facility will allow the Company to retire its existing facility (which will be demolished and retained to address and abate environmental concerns resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site). This new facility will house many employees currently working out of the existing service center. The Company anticipates a portion of these employees will have a hybrid work arrangement in which the employees perform some work tasks at the Lansing Service Center, some work tasks at other Company facilities, some work tasks at job sites, and some work tasks elsewhere including their homes. Employees with a hybrid work arrangement will require collaborative space and open office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Lansing Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Lansing Service Center; (3) Demolish the existing building and construct a new building on site; and (4) Construct a new facility at a new location, with multiple locations considered. The option to construct a new facility at a new location was determined optimal.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated in Exhibit A-137 (QAG-5), a Facilities assessment of the existing Lansing Service Center produced a score of 39, placing the existing Lansing Service Center in the quality designation of "Poor." This information led the Company to rule out a "do nothing" option, and problems with the existing facility's location led the Company to rule out building a new facility on the same site. The existing facility is built on the site of a former MGP, with impacted soil materials underlying the building and other structures. The existing facility is also located within the Grand River flood plain with the building floor elevation three feet below the river's flood stage. Additionally, the existing facility is located in a residential neighborhood and is served by a local road network with schools nearby, resulting in large truck traffic being routed through the residential area, which may be a safety hazard for residents (especially children). Crime in the existing area is also a problem as the site has experienced multiple law enforcement incidents involving the pursuit of armed suspects through the property, including areas within the secured perimeter, and stray shooting incidents. These incidents have resulted in the Company's

inability to move vehicles out of the service center (while police officers were pursuing suspects), and a general level of unease regarding the safety and security of employees.

Q. Please elaborate on the reasons the Company decided to build a new Lansing Service Center.

A. As reflected in the scores set forth in Exhibit A-137 (QAG-5), there are several reasons the Company has chosen to relocate the existing Lansing Service Center. These reasons range from the age of the building to customer accessibility. First, the existing service center building was built in 1958. Over time, systems of the building, including major mechanical and electrical systems, even with regular maintenance and replacement, are beyond their useful lives. Currently, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially zoned neighborhood and due to the location, does not allow Electric Operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All these considerations negatively impact the Company's ability to dispatch both personnel and equipment to serve customers. Other considerations supporting the decision to construct a new facility, rather than renovate the existing facility, include operating cost reductions, security, and environmental abatement. Because of all of these factors, the Company has decided to build a new Lansing Service Center at a new location.

Q. Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?

A. Yes. The site has experienced multiple law enforcement incidents. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the former use of the current Lansing Service Center site as the location of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e. coal tar residual). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition. Given these environmental issues, upgrades to the facility (e.g. carpet replacement and open space enhancement) cannot be cost effectively completed.

Q. Has the Company engaged in an environmental study for the area selected for the new Lansing Service Center?

A. Yes. The site for the Lansing Service Center includes previous agricultural use; thus, no environmental impacts exist from this previous use. A Phase 1 Environmental investigation has been completed. The site contains wetland areas and the Company is leaving these wetland areas undisturbed. A wetland assessment has also been completed.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Lansing Service Center?

A. The new Lansing Service Center facility is planned to be designed and constructed to standards that meet or exceed the USGBC, LEED version 4 rating system.

Q. The Lansing Service Center project includes the relocation of that facility to a different part of the Lansing metropolitan area. Can you explain what is considered generally when considering relocation of a facility?

A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that informs the Company of the possible need to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are evaluated for relocation to a newly constructed site with the goal of improved customer response. Facilities determined to already be optimally located within the customer service territory are evaluated for renovation or reconstruction on the existing site.

Q. How did the Company determine a new location for the Lansing Service Center?

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times. This analysis is reflected in Exhibit A-137 (QAG-5). Reducing customer response times lowers fuel costs by

minimizing the distance Company employees must travel to job sites. Determining the optimal area to minimize response times also maximizes employee efficiency by reducing labor hours required to reach and service customers. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Lansing Service Center within the service territory results in increased customer response times, higher fuel costs, and reduced employee efficiency due to increased travel times as explained above. The location for the new Lansing Service Center will not only be in a more appropriately zoned area but will also provide improved customer response times.

Q. Has land been acquired for the Lansing Service Center? If so, please identify the location of the land.

A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in Windsor Charter Township, at the southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821.

Q. What type of operations departments will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. The existing Lansing Service Center houses personnel from the following operating groups: Customer Experience, Electric Distribution, Electric Supply, External Affairs, Gas Delivery, Gas Engineering, Gas Operations, Grid Operations & Restoration, Information Technology, Low Voltage Distribution, and People & Culture. The Company anticipates personnel from these same operating groups to be housed in the new Lansing Service

Center. Company personnel (office-based personnel and operating personnel) needed to service customers in the Lansing area will be housed in the new Lansing Service Center.

Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. Approximately 430 employees are assigned to the existing Lansing Service Center. The Company anticipates the new Lansing Service Center will house a comparable number of employees with some adaptation in their use of the workspace including some employees adopting a hybrid work arrangement, requiring only collaborative space and open office space in the facility when they are on-site to work with other personnel.

Q. How large is the new Lansing Service Center building footprint as compared to the existing Lansing Service Center building footprint?

A. The existing Lansing Service Center building footprint is 121,240 square feet. The new Lansing Service Center building footprint will be 104,344 square feet.

Q. What is the status of the Lansing Service Center project at the time of this filing? What work has been completed so far, and what work is still remaining to be done?

A. The Lansing Service Center project is in construction. Building foundations are being completed, the site's storm water retention system is in development, and the main building, a prefabricated building, has been delivered. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design engineering and bidding have been completed and a municipal water main extension to the project site is fully constructed. A design-build contract for construction management services has been competitively bid and awarded. Programming of the building and architectural design of the building are

complete. The project plan for the new Lansing Service Center Project is detailed in Exhibit A-137 (QAG-5).

Q. Are there site plans, conceptual drawings, and building floorplans for the new Lansing Service Center?

A. Yes. See Exhibit A-137 (QAG-5).

Q. How much did the Company invest in the Lansing Service Center Project in the historical year in this case?

A. The Company invested $12,222,000 in the Lansing Service Center Project. See Exhibit A-135 (QAG-3).

Q. How much has the Company in total invested in the Lansing Service Center Project as compared to the allowance the Company received for this project in MPSC Rate Case No. U-20963?

A. As of December 31, 2025, the Company in total has invested $32,374,977 (gas allocation of $14,780,898 and electric allocation of $17,594,079) in the Lansing Service Center Project as compared to the allowance of $29,000,000 (gas allocation of $13,276,000 and electric allocation of $15,724,000) the Company received for this project in Case No. U-20963. See Exhibit A-137 (QAG-5), page 8.

Q. Please describe the Hastings Service Center project. What is its overall goal?

A. The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property the Company purchased from the adjacent landowner. This new facility will house employees currently working at the existing service center. A portion of the employees currently working at the existing service center

will have a hybrid work arrangement and will require collaborative space and open office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Hastings Service Center did the Company consider?

A. The Company considered four alternatives: (1) Do nothing; (2) Renovate the existing Hastings Service Center; (3) Demolish the existing building and construct a new building on site; and (4) Construct a new facility at a new site. The option to demolish the existing building and construct a new building on site was identified as optimal.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated in Exhibit A-137 (QAG-5), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, because this score falls below a score of 48, it was targeted for replacement, and the "do nothing" option was ruled out. For the same reason that the Lansing Service Center was targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement. The current site is fully developed and is no longer sufficient to support ongoing utility operations as the site lacks adequate space for both safe vehicle maneuvering and utility construction material storage. In addition, the existing building envelope does not comply with current energy code requirements. The Company, therefore, ruled out the renovation option for the Hastings Service Center. The existing Hastings Service Center site is located within an industrialized area with access to major roads. The Company determined that the facility is currently in an optimal location to service customers (see Exhibit A-137 (QAG-5)).

Therefore, with the acquisition of appropriate adjacent parcels, the Hastings Service Center was targeted for replacement on the existing site in lieu of relocation.

Q. Can you further elaborate on how these alternatives were compared?

A. The Company originally sought to construct a new facility on the existing property. Construction of the new Hastings Service Center on the existing property was predicated on reaching an agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy, which would increase the available site area for development and provide enough space for the new facility. Agreement for a property transfer with an adjacent landowner was initially not reached. The properties on the west and east are fully developed. The Company then entered negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). The Barry County Road Commission approved the Company's conceptual plan for development of this parcel. The Company completed acquisition of the parcel in March 2025 which will allow for expansion of the existing Hastings site and construction of the new facility.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Hastings Service Center?

A. The proposed new Hastings Service Center facility is planned to be designed and constructed to standards that meet or exceed the USGBC, LEED version 4 rating system.

Q. Will this building be larger or smaller than the existing Hastings Service Center?

A. The conceptual site plan for the new service center is shown in Exhibit A-137 (QAG-5). The projected building area based on conceptual data assembled is 48,440 square feet and is larger than the existing Hastings Service Center which is 13,011 square feet. The new facility is designed with a larger footprint to address multiple deficiencies at the existing

facility that negatively impact electric operations including insufficient space for crew rooms, parts and material storage, welding operations, and automotive tools and repairs.

Q. What type of operations departments will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses personnel from the following operating groups: Gas Distribution, Gas Service, Electric Distribution, Electric Service, Low Voltage Design, Work Management & Customer Delivery, Electric Meter Services, Planning & Scheduling, Facilities, Fleet, and Storeroom Operations. The Company anticipates personnel from these operating groups to be housed in the new Hastings Center.

Q. Approximately how many employees will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses 51 employees. The Company anticipates the New Hastings Service Center will house a comparable number of employees.

Q. What is the status of the construction of the Hastings Service Center at the time of this filing? What work has been completed so far?

A. The Barry County Road Commission (owner of the adjacent parcel to the south) has approved the Company's conceptual plan for development of the parcel. A Phase 1 Environmental Study, a Phase 2 Environmental Study, and a Baseline Environmental Assessment have been completed. The adjacent parcel to the south was acquired in March 2025. Programming and design of the new facility has commenced. The project plan for the new Hastings Service Center Project is detailed in Exhibit A-137 (QAG-5).

Q. How much did the Company invest in the Hastings Service Center Project in the historical year in this case?

A. The Company invested $51,000 in the Hastings Service Center Project in the historical year in this case. See Exhibit A-135 (QAG-3).

Q. How much has the Company in total invested in the Hastings Service Center Project as compared to the allowance the Company received for this project in MPSC Rate Case No. U-20963?

A. As of December 31, 2025, the Company in total has invested $357,909 (gas allocation of $163,310 and electric allocation of $194,599) in the Hastings Service Center Project as compared to the allowance of $11,500,000 (gas allocation of $5,265,000 and electric allocation of $6,235,000) the Company received for this project in Case No. U-20963. See Exhibit A-137 (QAG-5), page 28. Consistent with the Commission's Order in Case No. U-21585, the Company in this case will not seek an allowance for its Hastings Service Center Project. The Company will seek an allowance for this project when it demonstrates substantial progress on the project.

Renovations

Q. What capital expenditures are included in the Renovations portfolio category?

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-135 (QAG-3), the Company is projecting to spend $30,265,000 on Renovations in the bridge period and $10,904,000 on Renovations in the test year.

Q. Has the Company identified projects in the Renovations portfolio category?

A. Yes. As shown in Exhibit A-135 (QAG-3), the Company has identified the following Renovations projects:

- Kalamazoo Service Center
- Control/Dispatch Consolidation
- South Monroe Renovation
- OEP 5 Refresh
- OEP Legal Library Renovation
- Birch Run Acquisition
- New East Kent Project

In this testimony, the Company will provide information concerning these projects and their respective status.

Q. Describe the Kalamazoo Service Center project. What are its overall goals?

A. In this project, the Company is renovating the existing Kalamazoo Service Center. The Company is remediating asbestos concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The renovations of this facility entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Kalamazoo Service Center; and (3) Demolish the existing building and construct a new building on site. The option to renovate was identified as optimal.

Q. How did the Company decide to renovate the existing service center?

A. The Company originally planned to construct a new facility on the existing property, as Company witness Scott J. Bartholomew testified in his direct testimony in Case No. U-20963. The Company subsequently reevaluated its plans to ensure the renovated Kalamazoo Service Center is constructed in a manner that optimizes use of capital. In Case No. U-20963, the Company's projected total cost for the renovated Kalamazoo Service Center was $52 million. The Company's projected total cost for the renovated Kalamazoo Service Center is now $35 million, an approximate 33% reduction in cost. The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility. A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while controlling capital costs and minimizing disruptions to the Company's operations. Specifically, a renovation will minimize disruptions both to areas that house the Company's operating crews and to areas where the equipment and vehicles that crews use to service customers are maintained and serviced. Other considerations supporting the decision to renovate the existing facility include the fact that the Kalamazoo Service Center is already optimally located for responding timely to the Company's customers.

Q. Why is doing nothing not a viable option at this location?

A. As demonstrated in Exhibit A-138 (QAG-6), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 46. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e. spray applied fireproofing, pipe wrap, floor tiles, etc.). All employees at this site were moved to the second floor of the building due to air quality issues rooted in the growth of mold and related asbestos concerns on the first floor. This limited space is inadequate for the Company's Low Voltage Distribution employees to operate. As discussed above, because an assessment score of 46 falls below a score of 48, the Kalamazoo Service Center was originally targeted for replacement. In addition to its environmental concerns, the existing Kalamazoo Service Center was constructed in 1965, and its continuing use was determined inadequate due to aging infrastructure. Most of the existing systems throughout the facility are over 50 years old and beyond their useful lives. The space requirements of the existing workforce have changed as more personnel adopt a hybrid work arrangement requiring only collaborative workspace and open office space when they are in the office working collaboratively with others. Finally, the existing Kalamazoo Service Center is optimally located for responding timely to the Company's customers and, therefore, remaining at the current location best supports the Company's intent to provide timely service to its customers in the Kalamazoo area.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the renovated Kalamazoo Service Center?

A. The renovated Kalamazoo Service Center is being designed and constructed to standards that meet or exceed the USGBC, LEED version 4 rating system.

Q. What is the status of the renovation of the Kalamazoo Service Center at the time of this filing?

A. The Company has bid and awarded a contract for construction management services and a contract for architectural and engineering design services. Architectural design and engineering work on the project is complete. Renovation construction is underway with an expected completion date of June 2026. The project plan for the Kalamazoo Service Center Project is detailed in Exhibit A-138 (QAG-6), page 7.

Q. How much did the Company invest in the Kalamazoo Service Center project during the historical year of this case?

A. The Company invested $9,430,000 in this project during the historical year of this case. See Exhibit A-135 (QAG-3).

Q. How much has the Company in total invested in the Kalamazoo Service Center Project as compared to the allowance the Company received for this project in MPSC Rate Case No. U-20963?

A. As of December 31, 2025, the Company in total has invested $27,255,454 (gas allocation of $12,436,110 and electric allocation of $14,819,344) in the Kalamazoo Service Center Project as compared to the allowance of $30,702,000 (gas allocation of $14,056,000 and electric allocation of $16,646,000) the Company received for this project in Case No. U-20963. See Exhibit A-138 (QAG-6), page 8.

Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller than the existing Kalamazoo Service Center?

A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly from the size of the existing Kalamazoo Service Center because there is no anticipated change in the overall footprint of the facility.

Q. What type of operations departments will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. The existing Kalamazoo Service Center houses personnel from the following operating groups: Analytics, Customer Experience & Growth, Electric Supply, Community Engagement, Gas Delivery, Gas Engineering Planning & Supply, Gas Operations, Grid Operations Restoration & Work Management, Information Technology, Low Voltage Distribution, Business Support Services, Planning & Scheduling, and Human Resources. The Company anticipates these same personnel will remain housed in the renovated Kalamazoo Service Center.

Q. Approximately how many employees will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The Company anticipates the renovated Kalamazoo Service Center will house a comparable number of employees with some employees adopting a hybrid work arrangement and requiring only collaborative space and open office space in the facility when they are on-site to work with other personnel.

Q. Are there site plans, conceptual drawings, and building floorplans for the renovated Kalamazoo Service Center?

A. Yes. See Exhibit A-138 (QAG-6).

Q. Please describe the Control/Dispatch Center Consolidation project. What are its overall goals?

A. A complete description of the Control/Dispatch Center Consolidation project and its overall goals are outlined in the testimony of Company witness Jeffrey P. Dickey. This testimony is tailored very narrowly to a discussion of the building renovation that supports the Control/Dispatch Center Consolidation project.

Q. What benefits will the renovations constructed pursuant to the Control/Dispatch Consolidation project provide to customers?

A. The benefits to customers of the Control/Dispatch Center Consolidation renovations are outlined in the testimony of Company witness Dickey.

Q. How much does the Company project to invest in Control/Dispatch Center Consolidation renovations in the bridge period and test year in this case?

A. As shown in Exhibit A-135 (QAG-3), the Company is projecting to invest $20,093,000 in the Control/Dispatch Center Consolidation renovations in the bridge period and $1,557,000 in the test year.

Q. How have projected costs for the Control/Dispatch Center Consolidation renovations been derived?

A. Cost estimates were derived from fully engineered designs and quotes from contractors performing work on this project.

Q. What is the status of the Control/Dispatch Center Consolidation renovations at the time of this filing?

A. The Control/Dispatch Center Consolidation Project – Grand Rapids and the Control/Dispatch Center Consolidation Project – Parnall are both in construction. See Exhibit A-138 (QAG-6), pages 10-11.

Q. How much did the Company invest in Control/Dispatch Center Consolidation renovations during the historical year of this case?

A. The Company invested $5,514,000 in this project during the historical year of this case. See Exhibit A-135 (QAG-3).

Q. How much has the Company in total invested in the Control/Dispatch Center Consolidation Project as compared to the allowance the Company received for this project in MPSC Rate Case No. U-21389?

A. As of December 31, 2025, the Company in total has invested $8,000,946 in the Control/Dispatch Center Consolidation Project as compared to the allowance of $6,854,000 the Company received for this project in MPSC Rate Case No. U-21389. See Exhibit A-138 (QAG-6), page 12.

Q. Describe the South Monroe Service Center renovation project. What is its overall goal?

A. The purpose of this project is to acquire design and engineering services needed to remodel a portion of the Company's South Monroe Service Center interior. This remodel will provide adequate meeting space for Company crews and bring the facility into compliance with minimum code requirements specifying the number of restroom fixtures required per building occupant. The project will include construction of a building addition needed to

house utility construction equipment and maintenance materials such as cable ties, insulators, cable splices, and switches. The size of the existing South Monroe Service Center is no longer adequate to support operational needs. The workload assigned to the South Monroe Service Center has increased and the number of Company crews operating from the building has increased commensurately. This, in turn, has driven an increase in the amount of material necessary to support work at the site and an increase in the amount of space required in the building to support operational needs.

Q. What alternatives did the Company consider for this project?

A. The Company considered the following alternatives: (1) Do nothing; (2) perform an interior renovation; (3) perform an interior renovation and construct a building addition; and (4) perform an interior renovation and acquire an adjacent building in lieu of constructing a building addition. Doing nothing is not a suitable option because the existing building is no longer suitable to support operational needs and must be brought into compliance with minimum code requirements. An interior renovation (the second alternative) would provide adequate space for crew meetings and bring the building into compliance with minimum code requirements but is ultimately not suitable because it would not address the site's need for additional storage space. An interior renovation coupled with a building addition (the third alternative) and an interior renovation coupled with acquiring an adjacent building (the fourth alternative) would provide adequate space for crew meetings, will bring the building into compliance with minimum code requirements, and will meet the site's need for additional storage space. The fourth alternative was deemed optimal because the cost of acquiring an adjacent building is less

than the cost of building a comparable addition and it provides yard space for outdoor storage needs.

Q. Why did the Company choose to perform this renovation?

A. As noted, the South Monroe Service Center is not adequate to support the site's growing workload and is currently out of compliance with minimum code requirements specifying the number of restroom fixtures required per building occupant.

Q. What benefits will this building provide for customers?

A. The increased workload at the South Monroe Service Center is driven by an increase in the pace of system reliability work the Company is performing in the South Monroe area. The Company's customers in the South Monroe area directly benefit from fewer, shorter outages that result from a more reliable and resilient electric distribution system in the area.

Q. How much does the Company project to invest in the South Monroe Service Center renovation project in the bridge period and test year in this case?

A. As shown in Exhibit A-135 (QAG-3), the Company is projecting to invest $2,540,000 in the South Monroe Service Center renovation project in the bridge period and $0 in the test year.

Q. How have these projected costs been derived?

A. Outside consultants and contractors have been engaged to develop and prepare a detailed design program and construction schedule for the South Monroe Renovation Project. These firms have evaluated the design program, construction schedule, and received quotes for services to be performed to develop project cost estimates.

Q. What is the status of the construction of the South Monroe Service Center renovation project at the time of this filing?

A. The Company has bid and awarded a contract for architectural and engineering design services. Architectural and engineering design work on the project is complete and the project is now in construction. See Exhibit A-138 (QAG-6), page 14.

Q. Has the Company invested any capital in the South Monroe Service Center renovation project so far?

A. $1,475,000 has been invested in the South Monroe Service Center renovation project. See Exhibit A-135 (QAG-3), page 2.

Q. Describe the OEP 5 Refresh Project. What are its overall goals?

A. The OEP (One Energy Plaza) 5 Refresh Project centers on a renovation of the fifth floor of the Company's OEP Headquarters Building. The fifth floor of OEP is being renovated to create a collaborative workspace that will be used by Company personnel dedicated to supporting the SAP S4HANA Implementation Project as detailed in the direct testimony of Company witness Stacy H. Baker.

Q. What alternatives to the OEP 5 Refresh Project did the Company consider?

A. Alternatives to the SAP S4HANA Implementation Project are outlined in the direct testimony of Company witness Baker. This testimony is narrowly tailored to renovation of the fifth floor of OEP that will be used to support the SAP S4HANA Implementation Project.

Q. Why is doing nothing not a viable option for the OEP 5 Refresh Project?

A. Alternatives to the SAP S4HANA Implementation Project are outlined in the direct testimony of Company witness Baker. This testimony is narrowly tailored to renovation

of the fifth floor of OEP that will be used to support the SAP S4HANA Implementation Project.

Q. Are there energy efficiency and waste reduction measures the Company plans to execute as part of the OEP 5 Refresh Project?

A. Yes. New light emitting diode ("LED") lighting and smart LED sensors will be installed as part of this project. The Company estimates these energy efficiency measures will reduce energy usage by 77,293 kilowatts annually and contribute to carbon emission reductions of 65,784 pounds annually**.**

Q. What is the status of the OEP 5 Refresh Project at the time of this filing?

A. As of the time of this filing, renovations for the OEP 5 Refresh Project are complete.

Q. How much did the Company invest in the OEP 5 Refresh Project during the historical year of this case?

A. The Company invested $1,458,085 ($792,615 electric allocation and $665,470 gas allocation) in the OEP 5 Refresh Project during the 2025 historical year of this case. See Exhibit A-138 (QAG-6), page 18.

Q. How much has the Company in total invested in the OEP 5 Refresh Project?

A. As of December 31, 2025, the Company in total has invested $1,458,085 (gas allocation of $665,470 and electric allocation of $792,615) in the OEP 5 Refresh Project. See Exhibit A-138 (QAG-6), page 18.

Q. What type of operations departments will work on the renovated OEP fifth floor?

A. Subject matter experts from nearly every operating group in the Company will work on the renovated OEP fifth floor alongside the Company's information technology personnel and assorted third-party support personnel.

Q. Approximately how many personnel will work on the renovated OEP fifth floor?

A. Approximately 200 personnel in total (employees and transient third-party contractor personnel) utilize this space on the fifth floor of OEP daily in support of this project.

Q. Describe the Legal Library Renovation Project. What are its overall goals?

A. The purpose of this project is to convert space now used as a library for the Company's Legal Department to large (100 or more occupants) conference room space coupled with smaller collaboration spaces. This space is located on the 11th Floor of the Company's One Energy Plaza Headquarters. Large conference room space in the Company's One Energy Plaza Headquarters has become increasingly scarce as teams of Company personnel spend more time together in the office engaged in collaborative problem solving and instruction as opposed to working individually at desks or in single workstations. In addition, the evolution of digital technology has rendered obsolete most of the physical books and paper documentation previously retained in the Company's Legal Department. Therefore, the Company determined that this space is best utilized as large conference room space.

Q. What alternatives to the Legal Library Renovation Project did the Company consider?

A. The Company has not considered any other alternatives to this project. The Company does not consider doing nothing a viable option because this space will remain underutilized otherwise and gradually reduce the productivity of Company personnel in need of large conference room space at the Company's One Energy Plaza headquarters. This alternative also enables the Company to avoid the expense of renting third party space for gatherings that can be accommodated within its One Energy Plaza facility by performing this renovation.

Q. How did the Company decide to renovate the existing legal library?

A. The Company decided to renovate the existing legal library upon receiving repeated and sustained requests from Company personnel for additional large conference room space at One Energy Plaza. The Company is also committed to maximizing the efficiency of its facilities by ensuring available space is fully utilized.

Q. What is the status of the Legal Library Renovation project at the time of this filing?

A. The Company has received a rough order of magnitude (ROM) cost estimate for the project and has begun conceptual design of the space to be renovated.

Q. How much has the Company in total invested in the Legal Library Project?

A. As of the time of this filing, the Company in total has invested $0 in the Legal Library Project. See Exhibit A-135 (QAG-3).

Q. Is the projected size of the renovated Legal Library larger or smaller than the existing legal library?

A. The renovated space will be identical in total area to the existing legal library space.

Q. Approximately how many employees will routinely use the renovated Legal Library?

A. The renovated Legal Library space will be available to all Company employees. Over 800 Company personnel are assigned to the One Energy Plaza facility. The Company anticipates personnel assigned to the One Energy Plaza facility will be among the most frequent users of this renovated space

Q. Are there conceptual drawings and/or building floorplans for the renovated Legal Library?

A. Yes. See Exhibit A-138 (QAG-6), page 20.

Q. Describe the Birch Run Acquisition Project. What is its overall goal?

A. The Birch Run Facility, located at 11556 North Dixie Highway, Birch Run, MI 48415, is used as a material staging ground and operations center from which Company personnel are dispatched to connect new business customers with electric service. Company personnel from this facility serve thousands of customers located within an approximate 25 mile radius. The current owner of the Birch Run Facility has informed the Company that he intends to sell the facility and offered the Company an option to purchase it. It is likely that a new owner of the Birch Run Facility may evict the Company because a new owner would likely use the facility for a different business purpose. This possibility would require the Company to secure an alternate location for its personnel and materials now located at the Birch Run Site. The Company's options to secure an alternative location are limited and not optimal as compared to securing the Birch Run Facility.

Q. What alternatives to acquiring the Birch Run Site did the Company consider?

A. The Company considered the following four alternatives: (1) Do nothing; (2) Find a new location to lease or acquire in the area; (3) Construct a new building on land in the area; and (4) Acquire the existing Birch Run Site and perform any structural repairs and improvements deemed essential. The alternative to acquire the existing facility was identified as optimal. Doing nothing is not a viable alternative because, as noted, the Company risks eviction from the site and no comparable facilities are available in the area. The Company estimates that constructing a new facility on land in the area would cost $9,750,000 given current construction cost estimates. Therefore, this alternative is not optimal. See Exhibit A-138 (QAG-6), page 22.

Q. What benefits does the Company expect to realize from the Birch Run Acquisition Project?

A. A portion of the Company's Electric Underground Construction workforce is assigned to the Birch Run Site. If the Company is evicted from the Birch Run Site, the Company will be required to engage contractors to perform the work now performed by the Company's Electric Underground Construction workforce resident at the Birch Run Site. The Company would have incurred additional expense of approximately $5 million in calendar year 2025 had the work now performed by the Company's Electric Underground Construction workforce at the Birch Run Site been performed by outside contractors.

Q. Has the Company completed all necessary and prudent environmental reviews of the Birch Run Site?

A. No. As of the time of this filing, the Company is performing due diligence that includes but is not limited to prudent environmental reviews. The Company has not completed these environmental reviews.

Q. Does the Company plan to perform any renovations of the Birch Run Site upon acquisition? If so, please describe.

A. Yes. As of the time of this filing, the Company is performing due diligence and estimates needed improvements to the site totaling $947,000. Needed improvements include but are not limited to replacement of the roof, security and fence upgrades, and a new water supply.

Q. What is the status of the Birch Run Acquisition Project?

A. The Company is negotiating an option agreement for the Birch Run Site that will include termination of the existing lease agreement. As of the time of this filing, the Company anticipates a Strike Price in the option agreement of $4.924 million. As noted, the

Company is also performing due diligence, which includes but is not limited to survey evaluation, title review, building condition assessment, and environmental reviews.

Q. What type of operations departments will work at the Birch Run Site upon acquiring the facility?

A. The Birch Run Site houses personnel from the following operating groups: Gas Construction and Electric Underground. The Company anticipates these same personnel will remain housed in the Birch Run Facility upon acquiring it.

Q. Approximately how many employees will work at the Birch Run Site upon acquiring the facility?

A. Approximately 40 employees are assigned to the Birch Run Site. The Company anticipates the facility will house a comparable number of employees upon acquiring the facility.

Q. How large is the Birch Run Facility?

A. The Birch Run Facility is 37,500 square feet. The area of the site on which the facility is located totals 34.27 acres. The Company anticipates the contiguous agricultural land on the site will be used to store materials and equipment and to provide area for Electric Underground and other operations personnel at the site to conduct operational training.

Q. Are there site plans, conceptual drawings, and / or building floorplans for the Birch Run Site?

A. Yes. See Exhibit A-138 (QAG-6), pages 24-26.

Q. How much in rental costs for the Birch Run Site did the Company expend during the historical year in this case?

A. The Company expended $320,589 in rental costs for the Birch Run Site during the historical year in this case.

Q. How much in rental costs for the Birch Run Site did the Company expend during calendar year 2024?

A. The Company expended $311,251 in rental costs for the Birch Run Site during calendar year 2024.

Q. Describe the New East Kent Project. What is its overall goal?

A. The Company is negotiating the purchase of a new facility located at 3881 North Greenbrooke Drive SE, Kentwood, MI 49512 to replace the Company's existing East Kent Service Center, located at 4501 40th Street S.E., Kentwood, MI 49512. The Company's existing East Kent Service Center is a leased property and lacks area for an equipment or storage yard. Material deliveries to this site have increased considerably as the Company continues performing electric reliability work pursuant to its electric reliability roadmap. These material deliveries to this site have become problematic due to the site's limited space. See Exhibit A-138 (QAG-6), page 26. In addition, the garage and parking area at this site are essentially the same space and, hence, the Company is not able to assign multiple mechanics to work simultaneously at the facility even as the number of units of equipment needed at the site grows. Finally, the current facility is experiencing air quality issues that require improvements to the HVAC building system. A preliminary estimate of the cost of these needed improvements totals $3.2 million, a sum greater than the estimated value of the property which is $2.4 million. The Company therefore does not believe investing further capital into its existing East Kent Service Center is financially prudent or in the best interest of the Company's customers.

Q. What alternatives to the New East Kent Project did the Company consider?

A. The Company considered the following four alternatives: (1) Do nothing; (2) perform minimal O&M repairs to address some air quality issues; (3) perform renovations including complete improvements to the HVAC building system; and (4) acquire a new facility within the customer service territory now served by the existing East Kent Service Center that offers yard space for materials and equipment essential to the Company's electric reliability work and has no air quality or other deficiencies in its HVAC building system. The alternative to acquire a new facility was identified as optimal. Doing nothing is not a viable alternative because of the health and safety problems presented by known air quality problems at the current site. The alternative to perform minimal O&M repairs totaling approximately $500,000 would mitigate some air quality issues at the site for a short period of time but would not mitigate all known air quality problems. This alternative also would not address the considerable operational difficulties that exist because the site lacks adequate yard and storage space for materials and equipment. The alternative to perform renovations including complete improvements to the HVAC building system would resolve known air quality issues but, as noted, the cost of this alternative exceeds the value of the facility. This alternative too would not address the considerable operational difficulties that exist because the site lacks adequate yard and storage space for materials and equipment.

Q. Has the Company completed all necessary and prudent environmental reviews of the proposed New East Kent Facility?

A. No. As of the time of this filing, the Company is performing assorted due diligence and has not yet completed necessary and prudent environmental reviews.

Q. Does the Company plan to perform any renovations of the New East Kent Facility upon acquisition? If so, please describe.

A. Yes. The Company intends to perform assorted renovations estimated at $4 million to modify the new facility and make it functional as a Company service center. These renovations include but are not limited to: installation and/or construction of showers / locker rooms for operating crews, wellness rooms, a garage for fleet vehicles and equipment, makeup air units, overhead doors, outdoor fencing, yard improvements, and truck ports.

Q. What is the status of the New East Kent Project?

A. The Company is performing assorted due diligence on the facility and is negotiating a purchase agreement for the facility. As of the time of this filing, the current owner of the building has offered to sell the facility for $5.2 million. See Exhibit A-138 (QAG-6), page 27.

Q. What type of operations departments will work at the New East Kent Facility upon acquiring the facility?

A. The East Kent Service Center houses personnel from the following operating groups: Low Voltage Distribution, HVD Engineering, and Shared Services. The Company anticipates these same personnel will occupy the New East Kent Service Center upon acquiring it with approximately 20 additional Electric Operations personnel being assigned to the site by December 2027.

Q. Approximately how many employees will work at the New East Kent Facility upon acquiring it?

A. Approximately 40 Company personnel will work at the New East Kent Facility upon acquiring it with approximately 20 additional personnel being assigned to the site shortly thereafter.

Q. How large is the New East Kent Facility?

A. See Exhibit A-138 (QAG-6), page 27.

Q. Are there site plans, conceptual drawings, and/or building floorplans for the New East Kent Facility?

A. Yes. See Exhibit A-138 (QAG-6), pages 26 - 29.

Q. How much has the Company invested in the New East Kent Project?

A. The Company has invested $0 in the New East Kent Project as of the time of this filing.

O&M Spending Overview

Q. What O&M expenses are included in "Facilities" in Exhibit A-134 (QAG-2), line 1?

A. Facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting. The Company maintains data on maintenance history in its buildings. This data, in conjunction with historical spend, is used to forecast projected Facilities O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

Q. What O&M expenses are included in "Real Estate" in Exhibit A-134 (QAG-2), line 2?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguarding of the public. This includes management of all

land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, landowner requests for modification of easement rights or approval of permission to construct within an easement, as well as management of all corporate facility leases. The group also responds to all requests to sell property or grant easements, leases, or licenses to third parties. Included in real estate services is the records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of way. The Company reviews its needs for real estate services annually. This information, in conjunction with historical spend, is used to forecast projected Real Estate O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Joshua W. Hahn, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am a Principal Engineer in the Electric Supply Planning Department.

QUALIFICATIONS

Q. Please briefly describe your educational background.

A. I received a Bachelor of Science Degree in Mechanical Engineering in 2008 from Michigan Technological University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2010. I was responsible for analysis of Financial Transmission Rights ("FTRs") and acquisition of FTRs through monthly and annual allocations and auctions, as well as maintaining the Company's short-term Load and Market Price models using MetrixIDRTM. In June 2012, I assumed primary responsibilities for the maintenance of the PROMOD IV Full Transmission production cost model. From January to September 2013, I assumed temporary responsibility for maintenance of the PROMOD IV production cost model and all analyses developed using the tool, including all fuel and purchased and net interchange forecasting. Later, in June 2015, I was again assigned responsibility to maintain the model and perform all analyses developed using PROMOD IV. In January 2016, I assumed responsibilities as the primary PROMOD IV modeler for near-term fuel and purchased power expenses.

Q. What are your present responsibilities and duties as a Principal Engineer?

A. I am responsible for modeling and analysis of fuel and purchased and net interchange power costs that are used in developing the Power Supply Cost Recovery ("PSCR") Plan and updating the PSCR factor. Additionally, I am responsible for generation unit outage analyses.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the following MPSC cases:

- Case No. U-17918-R 2016 PSCR Reconciliation case;
- Case No. U-18402 2018 PSCR Plan case;
- Case No. U-20068 2017 PSCR Reconciliation case;
- Case No. U-20219 2019 PSCR Plan case;
- Case No. U-20202 2018 PSCR Reconciliation case;
- Case No. U-20525 2020 PSCR Plan case;
- Case No. U-20220 2019 PSCR Reconciliation case;
- Case No. U-20649 2020 Voluntary Green Pricing case;
- Case No. U-20802 2021 PSCR Plan case;
- Case No. U-20526 2020 PSCR Reconciliation case;
- Case No. U-21009 2020 Renewable Energy Reconciliation case;
- Case No. U-21048 2022 PSCR Plan case;
- Case No. U-20803 2021 PSCR Reconciliation case;
- Case No. U-21257 2023 PSCR Plan case;
- Case No. U-21049 2022 PSCR Reconciliation case;

- Case No. U-21423 2024 PSCR Plan case and;
- Case No. U-21258 2023 PSCR Reconciliation case; and
- Case No. U-21592 2025 PSCR Plan case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is: (i) support PSCR costs expected to be incurred during the test year period beginning from May 1, 2027 and ending April 30, 2028; (ii) discuss the Company's State Reliability Mechanism ("SRM") capacity charge inputs, cost offsets, demand, and reconciliation; (iii) provide an update of Midcontinent Independent System Operator, Inc.'s ("MISO") Seasonal Resource Adequacy Construct; (iv) support the value of continued investment in the Company's generation assets; and (v) support the value of the Company's Demand Response ("DR") programs.

Q. How is your testimony related to the testimony of other Company witnesses?

A. Company witness Eugene M. Breuring's direct testimony ties to the PSCR costs, Large Economic Development ("LED") Rate, and Long-Term Industrial Load Retention Rate ("LTILRR") revenues. Company witness Emily A. Davis discusses the SRM charge and how the SRM relates to the Cost of Service. Company witness Mark E. Wittbrodt describes the Company's generation asset investment plan. Company witness Alex M. Gast addresses the Company's planned spending and growth of DR programs. Company witness Thomas P. Clark supports Integrated Resource Plan ("IRP") Settlement storage projects.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-140 (JWH-1)	Power Supply Cost Recovery Forecast for May 1, 2027 – April 30, 2028;

Exhibit A-141 (JWH-2)	Consumers Energy Forecast – Energy Market Sales Revenue and Total Variable Expense; and
Exhibit A-142 (JWH-3)	Summary of PPA Changes from September 30, 2025 – February 1, 2026.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

POWER SUPPLY COST RECOVERY

Q. Please explain power supply charges applicable to the Company's customers.

A. Power supply charges are applicable to the Company's full-service customers only. Full-service customers receive power supply service, including generation and transmission costs, as well as delivery service from the Company. Retail Open Access ("ROA") customers only receive delivery service from the Company and obtain their power supply service from an authorized alternative electric supplier.

Q. Are the Company's power supply costs recoverable?

A. Yes. All the Company's reasonably and prudently incurred power supply costs are recoverable. Power supply costs are forecasted in an annual PSCR Plan filing with the MPSC and subsequently reconciled in a related annual PSCR Reconciliation filing with the MPSC. Forecasting, reconciliation, and recovery of PSCR costs are governed by Michigan statute, MCL 460.6j, 1939 PA 3.

Q. Please explain how PSCR-related costs are included in this filing.

A. PSCR costs are included in this filing as a forecast of expenses for the projected test year beginning May 1, 2027, and ending April 30, 2028. PSCR expenses are recovered monthly from full-service customers through a PSCR factor as described and estimated in this case by Company witness Breuring. A portion of the PSCR expenses related to the cost of

capacity are utilized to calculate the SRM charge as discussed by Company witness Davis and as discussed later in this direct testimony.

Q. Please explain Exhibit A-140 (JWH-1).

A. Exhibit A-140 (JWH-1) is the forecast of the Company's generation requirements, transmission expenses, and purchased and interchange expenses for the projected test year ending April 30, 2028. The total system requirements represent the projected total energy supply requirements, presented in MWh, to serve customer load. The total system requirements are projections of energy production (or consumption) based upon generation requirements from energy load forecasts, unit heat rates, maintenance schedules, unit random outage rates ("RORs"), fuel costs, and unit net demonstrated capabilities. Variable expenses are a forecast based upon the projected MWh, commodity price forecasts, power purchase agreement ("PPA") variable cost provisions, and renewable energy transfer costs. Total capacity and PPA costs are based upon the capacity forecast for the Company and approved contract terms of the contracts. Also included are MISO cost projections for transmission and energy markets administration, as well as chemical reagent costs based upon generating unit energy production forecasts. The LTILRR revenues, and the LED rate, lines 43 and 44, respectively, of Exhibit A-140 (JWH-1) are shown separately such that the forecasted total power supply costs recovered from the remaining full-service customers can be shown on line 45 of Exhibit A-140 (JWH-1). The total power supply cost levels are consistent with prior years.

Q. How were the values in Exhibit A-140 (JWH-1) derived?

A. The values were derived from the Aurora Production Costing Program ("Aurora"), which was the same platform used in the Company's 2021 IRP filing, Case No. U-21090 as well

as all of the Company's PSCR Plan case and Rate Cases filed since Case No. U-21090. Aurora is a computer software application developed by Energy Exemplar ("EE") that supports electric utility decision analysis and corporate strategic planning. Aurora simulates the dispatch of the Company's generating resources, purchased power resources, and interchange power resources to meet projected customer electric demand requirements. The projected customer electric demand requirements are discussed in further detail in Company witness Breuring's testimony.

The primary inputs to Aurora are projected system loads, unit heat rates, maintenance schedules, unit RORs, fuel costs, unit net demonstrated capabilities and purchased and interchange ("P&I") power availability and costs. The model used by Aurora is structured to align as closely as possible with the way that MISO operates and administers the energy market. The system load and system generation requirements data were provided by Company witness Breuring. Coal, oil, and natural gas costs were provided by the Company's Fossil Fuel Supply Group. Information about the Company's generating units was provided by the Company's Plant Operations Group and discussed in the testimony of Company witness Richard T. Blumenstock.

The primary outputs yield a monthly cost amount for: (i) each unit of energy in the system requirements; (ii) any variable expenses; (iii) capacity, fixed and purchased Non-Utility Generators ("NUG") costs; as well as (iv) power supply costs, value of delivered energy, total expenses, and any revenue credits. This model is also used to develop the Company's presentation in its annual PSCR Plan cases.

Q. What expenses are included in the PSCR forecast?

A. PSCR expenses include both fixed and variable expenses. Variable expenses include, but are not limited to, fuel expense, variable purchased energy, and MISO interchange, as well as a portion of the Company-owned facilities included in the Renewable Energy Plan ("RE Plan"), as shown on lines 15 through 26 of Exhibit A-140 (JWH-1). Fixed expenses include, but are not limited to, purchases of fixed energy and capacity, as well as renewable energy transfer costs for a portion of the Company-owned facilities included in the RE Plan, as shown in lines 28 through 33 of Exhibit A-140 (JWH-1).

Q. Please explain any difference between the 2027 and 2028 forecasts filed as part of the 2026 PSCR Plan filing, and the forecast presented in this electric rate case filing.

A. The PSCR costs are included in this filing as a forecast of expenses for the projected test year beginning May 1, 2027 and ending April 30, 2028 as opposed to the full 2026 calendar year cost projections presented in the 2026 PSCR Plan filing (Case No. U-21873). Additionally, updated information for all main inputs mentioned above were included in a February 2026 update of the PSCR model previously utilized in support of the 2026 PSCR Plan. Changes include updated forecasts for electric sales, fuel pricing, generation outage schedules, and PPAs.

Q. Please detail the line items in Exhibit A-140 (JWH-1).

A. Total system requirements (expressed in units of MWh) for the projected test year ending April 30, 2028 are shown on page 1, line 14, and are based on projections provided by Company witness Breuring. Category-level detail comprising the total system requirements is shown on page 1, lines 1 through 13, and is the output of the Aurora production cost modeling and supplied inputs mentioned above.

The total annual fuel and variable purchased and net interchange PSCR expense, excluding any fixed energy and capacity expense, is shown on page 1, line 27 (expressed in units of thousands of dollars). This information was derived using production cost simulations and inputs as previously discussed. Exhibit A-140 (JWH-1), lines 28 through 33, present the fixed and capacity-related costs included in PSCR expense.

Line 35 shows the projected transmission expense that is expected to be recovered as part of the Company's power supply costs in PSCR proceedings. In Case No. U-14274, the Commission ordered that transmission costs are approved for inclusion in the Company's PSCR Plan and Reconciliation filings.

Lines 36 and 38 through 41 show reagent expenses for pollution control at the Company's fossil generation plants which are expected to be recovered as part of the Company's power supply costs in PSCR proceedings.

The total PSCR costs are shown on Exhibit A-140 (JWH-1), page 1, line 42. A portion of the PSCR expense is recovered under the LTILRR and a portion of the PSCR expense is recovered under the LED rate. These amounts are shown on page 1, lines 43 and 44, and the remaining PSCR expense to be recovered from remaining full-service customers is shown on page 1, line 45.

Pages 2 and 3 of Exhibit A-140 (JWH-1) summarize the purchased and net interchange power volumes and corresponding expenses or revenues projected to be incurred by the Company in the projected test year. These pages detail the volume associated with purchases from PPAs and markets shown in the Total Received, page 2, line 50, with deliveries shown in the Total Delivered, page 2, line 53, category of Exhibit A-140 (JWH-1).

Q. Please explain the expenses for Company-owned resources included in the RE Plan.

A. In general, for most Company-owned resources, there is no fixed expense included in PSCR expenses. The exception[1] to this is presented on page 1, line 29, of Exhibit A-140 (JWH-1) where the Company-owned renewable capacity (or fixed-expense related) component of the transfer price associated with the Company's owned renewable resources is provided, complementing the energy (or Company-owned variable-expense related) component of the transfer price presented on page 1, line 19, of Exhibit A-140 (JWH-1).

Q. Please explain how PPAs are structured.

A. PPAs include both fixed and variable costs. Some PPAs define payments as "capacity" payments, "fixed energy" payments, and "variable energy" payments. Capacity payments and fixed energy payments are generally regarded as fixed expenses because they are expected to be incurred regardless of the amount of energy delivered by the supplier. Variable energy payments generally reflect the cost of purchasing a MWh of energy from a supplier and thus vary depending on the amount of energy delivered. Variable energy payments therefore are similar to the variable expense (e.g., fuel cost) associated with producing a MWh of energy at a Company-owned facility.

Some other PPAs provide for a single price to be paid for each unit of energy to be delivered based on a capacity price and a combined fixed and variable energy price. Generally, these types of contracts are not dispatchable by the Company, thus the amount to be paid is likely limited by the physical capability of the supplying facility. In these

[1] Fixed expense related to transfer costs is an allowable cost included in PSCR cases under Public Act 295 of 2008 ("Act 295"), as modified under Public Act 235 of 2023, the Clean and Renewable Energy and Energy Waste Reduction Act. MCL 460.1047(2)(b)(iv).

instances, we have estimated the fixed energy costs based on the rates upon which the contracts were originally modeled.

Under Act 295, other PPAs are included in the Company's rates based on the amount of cost allowed under state law to be transferred from the Company's Incremental Cost of Compliance to its PSCR costs through the transfer price mechanism. To estimate the amount of capacity, fixed energy, and variable energy expense associated with these transfer costs, the Company used the energy and capacity schedules approved by the Commission in Act 295 and through the Company's Annual Renewable Energy Cost Reconciliation Proceedings to determine the transfer expenses.

Energy or variable cost-related expense for the Company's PPAs is shown on Exhibit A-140 (JWH-1), page 1, line 25, labeled "Purchased (NUGs) Variable Cost." Capacity or fixed cost-related expense for the Company's PPAs is shown on Exhibit A-140 (JWH-1), page 1, lines 31 and 32, labeled "Purchased (NUG) Capacity" and "Purchased (NUG) Fixed Energy," respectively.

Q. For line items 28 through 33 shown on Exhibit A-140 (JWH-1), what are the fixed expenses in the PSCR forecast?

A. The Company is forecasting $2,450,796,000 of PSCR expense expected to be incurred during the projected test year ending April 30, 2028, of which $398,398,000[2] is fixed expense.

[2]See Exhibit A-140 (JWH-1), page 1, line 34, column (o).

Q. Are the projected fuel expenses and the projected purchased and interchanged power expenses shown on Exhibit A-140 (JWH-1) subject to any uncertainty?

A. Yes. The expenses are based on projections made by the Company of fuel costs, customer demand, generating unit availability, P&I power availability, P&I power prices, inflation, and other factors that cannot be predicted with precision. These projections were based on the best available information at the time the production cost modeling was completed to support this proceeding. It follows that any results from the use of these projections provide a reasonable but uncertain estimate of power supply costs.

Q. Have there been any changes to existing PPAs or new PPAs signed since the filing of the 2026 PSCR Plan case?

A. The Company has 14 new PPAs signed since September 2025, as listed in Exhibit A-142 (JWH-3). Ten of these PPAs replace generic PPA solar and storage blocks as part of the Company's IRP. The remaining four PPAs were signed as Public Utility Regulatory Policies Act of 1978 ("PURPA") solar.

Q. Please summarize your direct testimony regarding power supply charges.

A. The Company anticipates incurring approximately $2,450,796,000[3] in total PSCR expenses during the projected test year ending April 30, 2028, of which $122,209,000[3] is expected to be recovered under the LTILRR, $107,159,000[4] is expected to be recovered from LEDR, and $2,221,428,000[5] is expected to be recovered from remaining full-service customers.

[3] See Exhibit A-140 (JWH-1), page 1, line 43, column (o).
[4] See Exhibit A-140 (JWH-1), page 1, line, 44, column (o).
[5] See Exhibit A-140 (JWH-1), page 1, line 45, column (o).

SRM – CAPACITY CHARGE REVENUE OFFSETS AND DEMAND

Q. Please describe the SRM Capacity Charge.

A. In the Commission's November 21, 2017 Order in Case No. U-18239 ("November 21 Order"), the Commission adopted a methodology for determining the SRM Capacity Charge pursuant to Public Act 341 of 2016. The capacity charge "is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice" (November 21 Order, page 73) to ensure long-term resource adequacy to customers in the state.

Q. How is the capacity charge determined?

A. Company witness Davis's direct testimony describes how the capacity charge is calculated and what inputs are utilized in the calculation. As discussed in Company witness Davis's direct testimony, the SRM Capacity Charge calculation includes capacity cost offsets and a capacity charge demand used as the denominator of the capacity charge. These inputs rely on data that is detailed in this direct testimony below.

Q. Please define capacity cost offsets.

A. Capacity cost offsets are projected revenue(s) and associated fuel costs that are subtracted from the calculated capacity-related cost in developing the SRM Capacity Charge.

Q. Please identify the capacity cost offsets.

A. The capacity cost offsets used in the SRM calculation are:

(i) Energy Market Sales Revenue of $1,229,064,000 (line 12, Exhibit A-141 (JWH-2));

(ii) Off-System Energy Sales of $-1,000,000;[6]

[6] 2025 Actual Off-System Energy Sales, Ancillary Service Sales and Bilateral Energy Sales from Case No. U-21593, Exhibit A-28 (RTS-3) line 2, lines 3-4, and line 5, respectively.

(iii) Ancillary Service Sales of $9,000,000; [7]

(iv) Bilateral Energy Sales of $0[7] less; and

(v) Related Fuel Costs of $648,553,000 (line 24, Exhibit A-141 (JWH-2)).

Q. What is the basis for the above capacity cost offsets?

A. The Energy Market Sales offset is derived from the monthly volume of energy produced by generators owned or controlled by the Company as extracted from the Company's forecast of power supply costs for the projected test year (sum of lines 1 through 8 and lines 10 and 12 in Exhibit A-140 (JWH-1)) multiplied by the Company's forecast of the average monthly locational marginal price. The Off-System Energy Sales offset is based on the actual 2025 energy sales made to the Company's sole non-jurisdictional wholesale customer. The Ancillary Service Sales offset is based on the most recent-year historical value in this case. The Company made no bilateral energy sales in 2025 and does not forecast to make any bilateral energy sales in the projected test year ending April 30, 2028. Related Fuel Costs are the forecasted variable costs associated with the volume of Energy Market Sales as extracted from the Company's forecast of power supply costs for the test year (Exhibit A-140 (JWH-1), page 1, line 24).

Q. Is the Energy Market Sales offset the same as the Net Interchange Credits shown on Exhibit A-140 (JWH-1), page 3?

A. No. The Energy Market Sales offset is representative of the energy market value of the Company's entire generation fleet and PPAs and is calculated by multiplying the monthly energy produced by those resources by the forecasted average monthly locational marginal price. The Net Interchange Credit is the energy revenue of the generation fleet and PPAs sold into the MISO energy market in excess of the Company's load as calculated on an hourly basis. The Net Interchange Credit has been steadily declining over previous years

due to reduced sales and increased load. The two numbers explained above are derived from the same PSCR model (Aurora) and start from the same data source but are calculated and utilized differently in the filing.

Q. What is the value and source for the Capacity Charge Demand used in the SRM Capacity Charge calculation?

A. The Capacity Charge Demand value is 9,190 MW. This value represents Consumers Energy's actual total supply, including ROA, recorded in 2025. This value is sourced from the Company's most recent Securities and Exchange Commission Form 10-K filing, consistent with the Commission's determination in Case No. U-20963.

Q. What is the resulting SRM Capacity Charge that is proposed in this case?

A. As described by Company witness Davis, the SRM Capacity Charge calculation that is being proposed in this case is $201.84/MW-day.

Q. How does the SRM Capacity Charge proposed in this case compare to the SRM Capacity Charges approved in prior rate cases filed by the Company?

A. The SRM Capacity Charge approved was: $241.31/MW-day in Case No. U-21870; $65.13/MW-day in Case No. U-21585; $76.62/MW-day in Case No. U-21389; $244.80/MW-day in Case No. U-21224; $328.26/MW-day in Case No. U-20963; and $374.95/MW-day in Case No. U-20697.

Q. Have there been any proposed revisions to the SRM Capacity Charge calculation in previous cases?

A. Yes. In several previous cases, including Case Nos. U-20697, U-20963, U-21389, and U-21585, the Company proposed to use the zonal resource credit ("ZRC") value assigned to the Company's capacity resources in the denominator of the SRM Capacity Charge. In

Case No. U-20963 the Company proposed to amend an input for the Capacity Cost Offsets calculation, more specifically to include variable expense incurred by PPAs in the Related Fuel Costs offset. Additionally, in Case No. U-21585, Staff witness Nicholas M. Revere proposed that the SRM Capacity Charge calculation include an offset for the Company's net sales, effectively reducing the capacity cost for the Company, and ultimately ensuring unnecessary cost burden is not passed on to the customer.

Q. Were the SRM Capacity Charge calculation changes proposed by the Company approved by the Commission?

A. No. The proposals were rejected by the MPSC, based on the argument that the method for calculating the SRM Capacity Charge was originally approved in Case No. U-18239 and that any proposed changes to the calculation methodology would require that case be re-opened.

Q. Has the Company proposed any revisions to the SRM Capacity Charge calculation in this case?

A. No. The Company has not proposed any changes to the SRM Capacity Charge calculation in this case. However, following the Commission's prior guidance, the Company intends to further evaluate re-opening the original SRM Case No. U-18239 to propose a calculation methodology that does not result in a SRM Capacity Charge that prevents recovery of the Company's full capacity costs and, as a result, unfairly harms full-service customers. Additionally, the introduction of MISO's new Seasonal Construct, as I describe later in this direct testimony, will also impact the need to change the SRM Capacity Charge calculation's current calculation methodology.

ELECTRIC GENERATION CAPACITY

Q. In his direct testimony, Company witness Wittbrodt proposes capital investment and operating and maintenance expenses necessary to support the Company's electric generation fleet. Why is this spending important for the Company's customers in the context of electric supply and capacity planning?

A. As Company witness Wittbrodt explains in his direct testimony, the Company owns a diverse electric generation fleet comprised of fossil fuel, renewable (including hydroelectric), and energy storage assets. These assets are prudently managed and operated to ensure the supply of reliable and cost-effective electricity for customers. Continued investment and spending in the generation units are necessary to maximize the economic benefit delivered to customers in the form of both energy and capacity value. Company witness Wittbrodt provides a description of Net Energy Value ("NEV"), which the Company utilizes to analyze and quantify a generation asset's net benefit (relative to cost) to customers on an energy basis. From a capacity perspective, maintenance of the generation fleet is necessary to ensure the Company can meet resource adequacy obligations within MISO, as further described below. Both the energy and capacity value of the generation units ultimately underpin the power supply costs as presented earlier in this direct testimony.

Q. What is the connection between the generation reliability spending proposed by Company witness Wittbrodt and the capacity from those assets?

A. As discussed by Mr. Wittbrodt, generation reliability investments are expected to maintain or improve unit availability and reliability. Improvements in unit availability are expected to produce a corresponding improvement in the Seasonal Accredited Capacity ("SAC") for

those generating units. SAC is defined within the MISO Resource Adequacy Business Practice Manual BPM-011[7] as the anticipated capacity and availability of planning resources during times when they are most needed. Improvement in SAC and ensuring unit availability translate into increased capacity credit received from MISO in the form of ZRCs as well as increased NEV for the generating units. Company witness Wittbrodt provides additional discussion on the value of minimizing ROR and improving generating unit availability. The increased capacity credit supports the Company's requirement for meeting future planning reserve margin requirement ("PRMR") and reducing cost associated with the need to purchase third-party or market-based ZRCs.

Q. Please explain the MISO seasonal resource adequacy construct?

A. On August 31, 2022, the Federal Energy Regulatory Commission accepted MISO's proposal to implement seasonal resource adequacy requirements effective for the 2023/2024 planning year (see Case No. ER22-495-000, et al.). MISO's "seasonal construct" requires Load Serving Entity's ("LSEs") to meet the peak demand and load requirements for one peak hour per season (Summer, Fall, Winter, Spring). Summer season is defined as June 1 through August 31, Fall season is defined as September 1 through November 30, Winter season is defined as December 1 through last day in February, and Spring season is defined as March 1 through May 31. MISO's stated intended outcomes of moving to a Sub-Annual Resource Adequacy construct are to (1) identify reliability needs unique to each season, (2) align resource availability with seasonal needs, and (3) facilitate seasonal outages or partial year operations.

[7] Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/, accessed October 01, 2025.

In addition to the change from an annual to a sub-annual construct, MISO also changed the capacity accreditation methodology for thermal generating units and DR Resources. The capacity accreditation methodology changed from an Unforced Capacity, summer-focused construct, to a two-tier system based on real-time availability, with emphasis on the highest risk periods for each season. MISO has not yet changed the capacity accreditation methodology for non-thermal resources, except to adjust for seasonality.

Q. Please explain PRMR.

A. The PRMR is defined by MISO in the Resource Adequacy Business Practice Manual BPM-011 as the number of MW in ZRCs required to meet a LSEs Resource Adequacy Requirements ("RAR"). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable seasons. Consumers Energy is an LSE and is required to maintain sufficient capacity to ensure adequate electric supply in each Planning Year period for the projected LSE's load. The Company relies on MISO to determine the appropriate PRMR LSEs should maintain. The PRMR is calculated by MISO using: (i) the Company's forecast peak load coincident to MISO's peak load; (ii) a transmission loss percentage applicable to the Company; and (iii) a reserve margin to ensure reliability.

Q. Please explain what a ZRC is and how ZRCs are currently awarded for the Company's generation assets.

A. For thermal generation resources, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its availability which is based on the SAC calculation. The SAC calculation reflects the anticipated capability and availability of a generation

resource during times when they are most needed. This two-tier weighing structure is based on its real-time offered availability during seasonal Resource Adequacy ("RA") hours (Tier 2) and Non-RA hours (Tier 1). Resource Adequacy hours are based on emergency events, the tightest operating margin hours and maximum operating margin threshold. Operating margin is the amount of MW available divided by the amount of system load.

For intermittent generation resources, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its availability, which is based on historical performance during critical hours within each season, where new resources receive class average for that resource type until required historical data is accrued.

For reservoir hydroelectric facilities such as Ludington Pumped Storage, a ZRC is a capacity credit increment equal to 1 MW of generation resource, adjusted by its reliability, which is based on the Demand Equivalent Forced Outage Rate ("EFORd") calculation. Over each three-year period, startup, run time, and outage information is collected and categorized to determine the EFORd value for each generator. Prior to each Planning Year, MISO awards ZRCs to generator owners based on the lesser of the interconnection service limit and the Generation Verification Test Capacity ("GVTC"), multiplied by the result of one minus EFORd.

Q. What is the customer benefit of maximizing ZRCs for generating units?

A. Efficient capital investment in generator reliability allows the Company to maintain or improve the availability of its units and, as a result, maintain or increase the amount of ZRCs and the corresponding value realized to customers in the future. These ZRCs are a

key component of meeting the Company's PRMR and mitigating customer exposure to capacity price risk from insufficient capacity resources to meet the Company's PRMR.

Q. Please describe the risk if no additional investments are made.

A. If no additional investments are made, the deterioration of a plant's reliability is expected to increase over time, reducing the ZRCs assigned to the generating unit and therefore reducing the capacity value of the facility.

Q. How is capacity value assessed by MISO?

A. MISO administers a Planning Resource Auction ("PRA") annually, which "clears" seasonal ZRC offers to satisfy seasonal PRMR for each LSE. If sufficient resources are not available, the PRA cost of capacity may be driven to the Cost of New Entry ("CONE") or higher. CONE is an industry-wide concept that represents the annualized fixed costs of constructing and operating a new source of power to provide capacity. In the case of MISO, CONE represents the cost of constructing and operating a new simple cycle gas turbine fueled generator.

Q. At what cost has the CONE been set in recent years?

A. The CONE is published by MISO annually at the following rates in recent years for MISO Zone 7:

- Planning Year 2021/2022: $259.73/ZRC-day;
- Planning Year 2022/2023: $236.66/ZRC-day;
- Planning Year 2023/2024: $289.37/ZRC-day;
- Planning Year 2024/2025: $347.36/ZRC-day;
- Planning Year 2025/2026: $358.71/ZRC-day; and
- Planning Year 2026/2027: $376.74/ZRC-day.

Q. For comparison, what was the clearing price for capacity in MISO Zone 7 for each of the above Planning Years?

A. MISO Zone 7 cleared at the following prices in recent years:

- Planning Year 2020/2021: $257.53/ZRC-day;
- Planning Year 2021/2022: $5.00/ZRC-day;
- Planning Year 2022/2023: $236.66/ZRC-day;
- Planning Year 2023/2024:
  - Summer Season: $10.00/ZRC-day;
  - Fall Season: $15.00/ZRC-day;
  - Winter Season: $2.00/ZRC-day; and
  - Spring Season: $10.00/ZRC-day.
- Planning Year 2024/2025:
  - Summer Season: $30.00/ZRC-day;
  - Fall Season: $15.00/ZRC-day;
  - Winter Season: $0.75/ZRC-day; and
  - Spring Season: $34.10/ZRC-day.
- Planning Year 2025/2026:
  - Summer Season: $666.50/ZRC-day;
  - Fall Season: $91.60/ZRC-day;
  - Winter Season: $33.2/ZRC-day; and
  - Spring Season: $69.88/ZRC-day.
- Planning Year 2026/2027:
  - Summer Season: $424.3/ZRC-day;
  - Fall Season: $33.92/ZRC-day;
  - Winter Season: $35.97/ZRC-day; and

- Spring Season: $7.61/ZRC-day.

Q. If the cost of capacity were to go to CONE or higher, how would the Company's capacity cost be affected?

A. If MISO Zone 7 clears at CONE or higher, as it did in Planning Years 2020/2021, 2022/2023, 2025/2026 and 2026/2027, it is a signal that the Zone does not have enough capacity to meet the Zone's PRMR, which in turn means that there is an increased risk of system-wide reliability issues. If the Company is a net purchaser of capacity in a given year, an Auction Clearing Price of CONE or higher could result in PSCR cost increases to the Company's customers.

Q. What conclusion have you reached relative to the generation spending being sponsored by Company witness Wittbrodt?

A. The capital investment in the Company's generation fleet will provide for reliable and cost-effective power supplied to customers. This is true for both energy and capacity, where capacity is particularly necessary to meet resource adequacy obligations (*i.e.* PRMR) and avoid purchasing potentially high-cost capacity from the MISO capacity market.

Q. Is MISO's PRA the only way in which capacity value is determined?

A. No. As presented previously in this testimony, the MISO PRA does not necessarily "clear" at CONE in every year, and the value of capacity may be higher or lower than CONE on a per MW basis. The PRA is generally considered a "residuals" market, which is to say that load-serving entities largely enter into the PRA in a given year with sufficient (or nearly sufficient) resources to meet their requirement. Ensuring such sufficiency requires LSEs, like the Company, to follow standard procurement and development practices with regard to resource capacity. The Company engages in such activities, through annual and

sub-annual solicitations. The procurement of capacity is generally done through long-term PPAs or self-development and construction of new power plants.

Q. How does the Company value long-term capacity through its solicitation and development activities?

A. The Company has long recognized the value of capacity at approximately 75% of CONE. In recent years, as the balance between supply and demand is tightening, not just for the Company, but across all of MISO and beyond, the value of capacity has been observed to be higher than 75% of CONE.

DEMAND RESPONSE CAPACITY

Q. Please explain the types of DR programs expected to be employed by the Company in 2027 and 2028.

A. The Company's DR programs planned for 2027 and 2028 fall into one of two categories: (1) those that are directed by the Company; or (2) those that are dependent upon customer behavioral choices. DR programs controlled by the Company supply either a fixed quantity or range of energy. DR programs that are dependent upon customer behavioral choices provide energy reduction driven by rate structures that incentivize customers to use less energy during peak electric load periods. Additional details for specific DR programs are provided in the direct testimony of Company witness Gast.

Q. How are DR programs valued in terms of capacity credit in MISO's capacity market?

A. ZRCs are awarded by MISO for the Company's DR programs that are directed by the Company and registered by the Company as a capacity resource. The ZRCs are used to satisfy the Company's annual PRMR. For DR programs that are dependent upon customer behavioral choices, the Company reduces its peak load forecast by the amount of the DR

programs that are expected at peak load conditions. This reduction directly reduces the Company's PRMR.

Q. What are the forecasted DR Program levels for Planning Year 2026/2027 and 2027/2028?

A. For Planning Year 2026/2027 and 2027/2028, the Company will administer five DR programs that are controlled by the Company, including Air Conditioning Peak Cycling, Smart Thermostat Program, DR Contracts, DR Rate GI Reduce By, and DR Rate GI Reduce To. The total planned capacity of these DR resources to be registered with MISO in the summer season is approximately 691.5 ZRCs in Planning Year 2026/2027 and 686.6 ZRCs for Planning Year 2027/2028.

Also, for Planning Years 2026/2027 and 2027/2028, the Company will continue demand-side management programs that are dependent upon customer behavior, including Dynamic Peak Pricing, Energy Waste Reduction, Conservation Voltage Reduction, and Residential Summer on-peak rate. The total of these programs is approximately 924 MW for Planning Year 2026/2027 and 947 MW for Planning Year 2027/2028.

Per the MISO standard practice for demand-side management capacity planning, ZRC values reflect the expected MW reductions plus adjustments for transmission losses, planning reserve margin, and load diversity factors.

Q. What is the approximate market value of these DR resources?

A. Consumers Energy's Planning Year 2026/2027 DR portfolio is projected to total 605.5 ZRCs, valued at $59.5 million at an estimated value of capacity of $98,197/ZRC-Year.[8] Consumers Energy's Planning Year 2027/2028 DR portfolio is projected to total

[8] Based on 75% of MISO's calculated Planning Year 2025/2026 CONE.

664 ZRCs, valued at $66.5 million at an estimated value of capacity of $100,161/ZRC-Year. Similar to the generation capacity discussion earlier in this direct testimony, continued investment in growing the Company's DR programs is important to the Company's electric supply strategy (meeting PRMR obligations and avoiding potentially higher-cost market capacity purchases) and its broader Clean Energy Plan to further integrate cleaner supply and demand-side resources to cost-effectively meet customer demand.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

JOSHUA J. JUDY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Joshua J. Judy, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Fleet Acquisition & Asset Disposition.

Q. What is your formal educational experience?

A. I hold a master's degree in finance from the University of Michigan and a bachelor's degree in engineering from Michigan State University.

Q. What are your responsibilities as Fleet Acquisition & Asset Disposition Director?

A. I provide oversight to Fleet Acquisition supporting the Company's current and long-term capital replacement strategy, vehicle disposition, licensing, rentals, and internal electric vehicle ("EV") strategy. In addition, I provide oversight to the Company's Investment Recovery Center ("IRC") function, which handles the disposition of surplus Company assets.

Q. Would you please describe your previous work experience?

A. I have worked at Consumers Energy for 17 years. Before being promoted to my current role as Director of Fleet Acquisition & Asset Disposition in May 2025, I served five years as the Manager of Supplier Quality. My previous roles at the Company include positions in Electric Regulatory Strategy, Business Customer Service, Corporate Risk, and Smart Energy. Outside of work, I serve in a volunteer capacity on the Board of Directors for the Finance Committee at Eaton Community Health. My three-year term spans from April 1, 2025 to March 31, 2027.

Q. What is the purpose and scope of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's costs related to the electric business portion of Fleet services. To that end, I will:

- Describe the Company's Fleet and how it is managed through Fleet Services;
- Explain the Company's Fleet Replacement Planning Process;
- Explain the Company's Fleet Electrification Strategy; and
- Sponsor the Company's Fleet capital spending projections.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or "the Commission")?

A. Yes. I provided testimony in the Company's 2018-2019 Gas Cost Recovery Plan, Case No. U-18411, and the 2025-2026 Gas Rate Case No. U-21981.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (JJJ-1)	Schedule B-5.1	Summary of Actual & Projected Capital Expenditures Fleet Services;
Exhibit A-143 (JJJ-2)		Summary of Fleet Responsibility Costs;
Exhibit A-144 (JJJ-3)		Detailed List of Projected Electric Capital Expenditures Fleet Services;
Exhibit A-145 (JJJ-4)		Summary of Fleet Tooling Actual & Projected Capital Expenditures;
Exhibit A-146 (JJJ-5) Confidential		Projected Bucket Truck Maintenance and Repair Costs;
Exhibit A-147 (JJJ-6)		Impact of Reduced Fleet Purchases in Future Years;
Exhibit A-148 (JJJ-7)		Fleet Aging and Average Utilization Data;

Exhibit A-149 (JJJ-8)	Assessment of Fleet Electrification Viability;
Exhibit A-150 (JJJ-9)	Light Duty Purchase Plan EV Notes; and
Exhibit A-151 (JJJ-10)	Details Regarding Existing Vehicle Usage by Vehicle Specification.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (JJJ-1), Schedule B-5.1, details the actual and projected capital expenditures related to Fleet Services for the calendar year 2025, bridge period (16 months ending April 30, 2027), and the projected test year 12 months ending April 30, 2028. Exhibit A-143 (JJJ-2) provides details of the Company's fleet responsibility dollars. Exhibit A-144 (JJJ-3) provides the Company's Fleet acquisitions detailed List of Projected Electric Capital Expenditures Fleet Services. Exhibit A-145 (JJJ-4) is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2025, projected (12 months ending December 31, 2027), and the projected test year 12 months ending April 30, 2028. Confidential Exhibit A-146 (JJJ-5) is a confidential Summary of Projected Maintenance Cost Expenditures for eighty-eight bucket trucks removed from fleet deployment as a result of a boom tip failure, projected through 2028. Exhibit A-147 (JJJ-6) is a study regarding the impact of reduced vehicle purchases in future years as required in Case No. U-21870. Exhibit A-148 (JJJ-7) contains an Excel spreadsheet submitted in support of Exhibit A-147 (JJJ-6) that includes data related to the average utilization rates, and average age of Company fleet vehicles between years 2016 and 2025. Exhibit A-149 (JJJ-8) is an assessment regarding fleet electrification viability as required by the

requirement in Case No. U-21870. Exhibit A-150 (JJJ-9) is an Excel spreadsheet containing the vehicles in the five-year plan containing notes regarding consideration for electrification in support of Exhibit A-149 (JJJ-8). Exhibit A-151 (JJJ-10) is a Word document containing the descriptions of existing fleet vehicle usage by vehicle specification as required in Case No. U-21870.

FLEET SERVICES FUNCTION AND RESPONSIBILITIES

Q. What functions comprise the Fleet Services organization?

A. The Fleet Services organization consists of four departments which work collaboratively together to provide value to Electric Operations in serving customers. The four departments include Fleet Maintenance Operations, Fleet Acquisition, Fleet Regulatory and Tech, and Field Operations Analytics.

Q. Are you addressing all support organizations related to Electric Operations Support in your direct testimony and exhibits?

A. No. I will be addressing Fleet Services only.

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost-effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Acquisition.

A. Fleet Acquisition executes all functions related to the acquisition and disposition of Company-owned and rented vehicles and related equipment. This includes management

of the Fleet capital purchase plan, vehicle specification design, licensing/title, registration, and asset retirement. Specific to the Company's electric business, Fleet Acquisition's purpose is to provide vehicles and equipment that enable Electric Operations to serve customers with safe, reliable, and affordable electric service. This is accomplished by ensuring that the Company's Fleet assets are specified, procured, and delivered to the Company's Field Operations. Once delivered, Field Operations ensures that the units are maintained and operational to execute the work plan and respond to emergencies in the most efficient, cost-effective, and safe manner when required.

Q. Please explain the responsibilities of the Fleet Regulatory and Tech department.

A. This team is responsible for meeting all regulatory and compliance requirements with the American National Standards Institute, Department of Transportation, Michigan Motor Vehicle Code, and Federal Motor Carrier Safety Administration. Additional responsibilities include Fleet Operations Policies and Procedures, regulatory and technical support, and tooling for fleet mechanics and the Company's EV strategy. The department also provides oversight for quality inspection audits and safety requirements related to regulatory compliance.

Q. Please explain the responsibilities of the Field Operations Analytics department.

A. The Field Operations Analytics department provides fleet with data integrity support, Telematics data management (software installed in vehicles to provide information such as location, speed, fuel consumption, etc.), departmental metric visual management, process automation, oversight of waste elimination initiatives, and evaluates benchmarking and data analysis provided to the Company.

Q. Please explain the Company's overall fleet structure.

A. The Company's fleet includes approximately 7,607 owned, leased, and rented units across 36 locations. These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the Company categorizes its fleet into several specifications ("spec(s)"), each of which is a given type, model, and description of a vehicle. Each spec has a defined intended use, acquisition cost, operating cost, and expected life in years and mileage and in the case of equipment, hours.

Q. How is the Company's fleet divided between the electric and natural gas businesses?

A. The Company divides its fleet between the electric and natural gas businesses by determining which business unit at a given location is using each particular vehicle. The needs of the business require the deployment of dedicated teams to safely complete work utilizing specific tools and processes – this extends to the vehicle supporting said work. These vehicles are procured and customized to fulfil particular operational requirements, making them specialized for their designated tasks. Nevertheless, the Company actively identifies opportunities for units to be utilized and shared across various functions wherever feasible. The fleet location requirements will vary based on the service provided to the customer (electric, gas, or both), crew counts, and region. Additionally, some Company fleet units serve both electric and gas functions and are referred to as "common" units, which are utilized by support organizations, such as Facilities, Fleet, and Supply Chain. Overall, the Company's fleet is 40% electric, 50% gas, and 10% common by number of vehicles.

Q. Does the Company's fleet incur both capital and operating and maintenance ("O&M") costs?

A. Yes. The Company makes direct capital investments in its fleet as provided in Exhibit A-12 (JJJ-1), Schedule B-5.1, page 1. The Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars, which are presented in Exhibit A-143 (JJJ-2). The Company does not have specific Fleet O&M expenses. Fleet operating costs are reported in responsibility dollars.

Q. What are fleet responsibility dollars?

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars. Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determine which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.

A. Allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area. The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that respective

department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading**.**

Q. Can the Company identify to which budget line items, in various parts of the business responsibility dollars, are allocated and ultimately settled?

A. No. Fleet responsibility dollars are assigned to multiple work orders and ultimately settle to multiple cost centers making it difficult to determine with reasonable accuracy the allocation of fleet responsibility costs to specific line items in various parts of the business.

FLEET REPLACEMENT PLANNING PROCESS

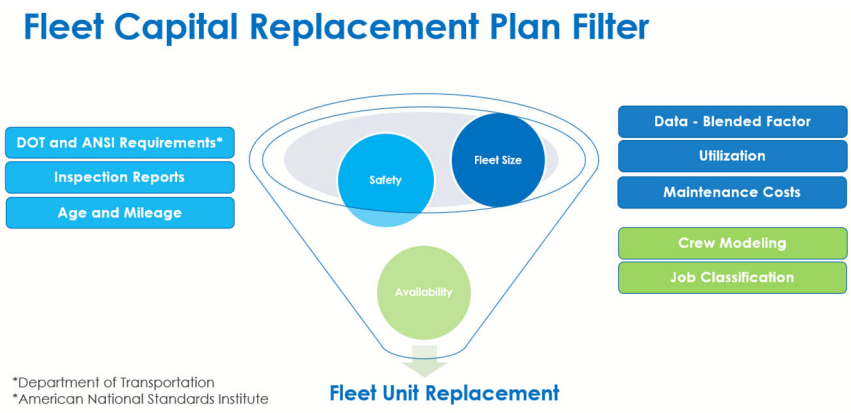
Q. What is the Company's overall Fleet Replacement Planning Process as it is being presented in this case?

A. As previously presented in Electric Rate Case Nos. U-20963, U-21224, U-21389,U-21585 and U-21870, and Gas Rate Case Nos. U-21148, U-21308, U-21490, U-21806, and U-21981, the Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet Replacement Planning Process, which is a process that incorporates three phases. In the first phase, the Company identifies vehicles that are at or near the end of their expected life and are eligible for replacement, using a tool called the Blended Factor that is described in more detail below. Next, in the second phase, the list of vehicles identified by Blended Factor Analysis for potential replacement is further developed by certain data tools, described below, particularly by fleet cost data, followed by crewing data, and, lastly, fleet utilization data. In this second phase, the Company's fleet leadership also works with Operations leadership and personnel in the field, which includes operators and mechanics, to identify which specific units should be replaced, incorporating qualitative inputs like maintenance reports and local area work needs. This second phase allows for further

evaluation of the vehicles identified in the first phase to better determine which vehicles should be replaced. Thereafter, in the third phase, the list of vehicles identified for retirement is finalized based on the evaluations performed in the first two phases, and the ordering process begins. If an existing contract is in place, orders are placed immediately with the manufacturer or vendor. For vehicles not covered by an existing contract, detailed specifications are written, and requests for proposals are sent to vendors. Once bids are received, they are evaluated and awarded based on cost, product support, and quality.

Q. Please further explain how the Company establishes its Fleet Replacement Planning Process.

A. The Company strives to replace assets at the optimal moment in the vehicle's service life by incorporating several factors in the decision-making process, particularly within phases 1 and 2. In doing so, the Company uses data gathered for each spec that is documented, monitored, and corroborated with detailed in-person inspections. Data is generated by the fleet through Telematics, including utilization rates, fleet age, and detailed inspections as a basis for determining future fleet purchases of specific capability and utility. The Company's process for compiling and analyzing qualitative and quantitative inputs to develop its Fleet Vehicle Capital Replacement Plan is illustrated by the "filter" shown below.



Q. Please explain how the Fleet Capital Replacement Plan Filter works.

A. When the Company goes through its Fleet Replacement Planning Process, specifically within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost, and crewing needs – is analyzed to determine if a given vehicle needs to be replaced. During the Fleet Replacement Planning Process, other qualitative inputs like vehicle inspection reports and the assessments by field employees provide further insight into replacement needs. The result of this process, specifically following the first and second phase, is a list of fleet units to be replaced.

Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?

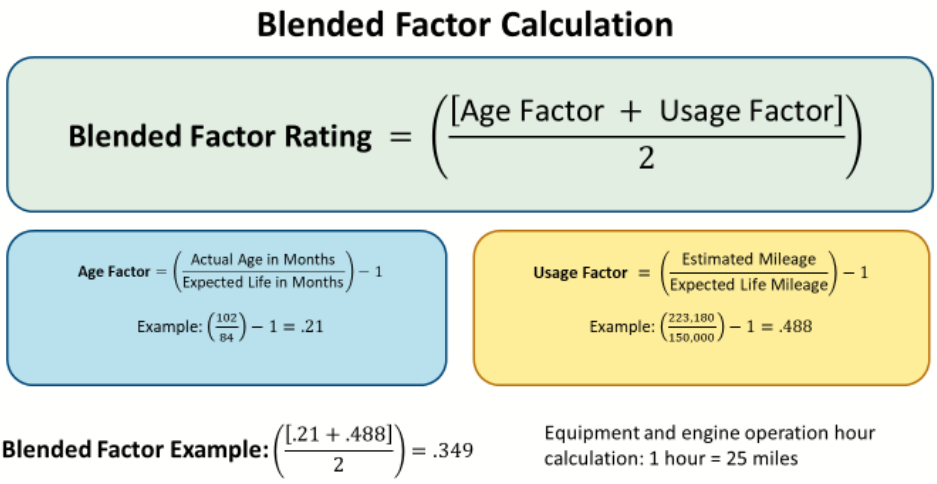
A. Yes. These are each described in the following sections.

A. Blended Factor

Q. Please further explain the Blended Factor.

A. The first step in the Company's process for establishing its Fleet Vehicle Capital Replacement Plan is informed by the Blended Factor. As previously mentioned, the Blended Factor takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to

maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative example below:



For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement. This indicator does not mean that a vehicle with a result greater than 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?

A. The Blended Factor formula incorporates two key indicators of how a vehicle reaches the end of its expected life: (1) how old a vehicle is; and (2) either how many miles it has traveled or total hours of operation. Expected life in months considers manufacturer inputs,

reliability, operating conditions, and operating cost to determine the duration the Company expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours is also based on similar considerations as an indicator of wear and tear. The Company makes these evaluations to set a foundational benchmark to assess potentially replaceable vehicles. The fleet has a diverse range of specs for specific operational needs, and not all specs have the same expected life. Even within the same spec, individual units can vary in condition depending on utilization and wear. Managing each spec to its appropriate life expectancy ensures that the Company always has the right type of vehicle available to serve the needs of customers in the safest, most reliable, and most efficient manner possible, while minimizing costs.

Q. Why is the use of the Blended Factor appropriate?

A. The Blended Factor is an internal data-based algorithm that incorporates unit age, utilization (in mileage or hours), and expected life, allowing the Company to prioritize, plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of the replacement process, the vehicles denoted by the Blended Factor to be approaching the end of their expected life provide the basis for planning phases ahead. This process is critical to ensure that the Company can order a timely unit replacement, especially given the supply chain challenges that have emerged in the last four years. While there has been some improvement in the expected delivery dates for some vehicles, planning around potential delivery delays and availability is still a concern as demand for new medium and heavy-duty equipment remains high. By using the Blended Factor, the Company can strategize future spending on replacement units for specific years by consulting with

suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

Q. What conclusions do you draw regarding the Blended Factor?

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of 7,607 units currently in the fleet, there are approximately 1,129 units greater than 0.00%.

B. Fleet Cost Tool

Q. Please explain the Company's fleet cost tool.

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet O&M costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile, by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

Q. What are these tools that the Company has developed to support fleet cost analyses?

A. For an overall summarization of fleet age and operating costs, the Company has developed PowerBI reports called "YOY Fleet Dashboard" and "Monthly Fleet Dashboard" tools to provide information regarding fleet operating costs correlated with age. The dashboard provides data on operating costs including cost per mile, maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec and can assist in identifying trends that will enable cost forecasting to support future purchasing decisions.

Q. What are additional analytical tools related to fleet cost?

A. The PowerBI report called Acquisition Purchase Plan identifies equipment count by spec and is designed to highlight yearly fleet growth by spec, which helps identify trends, costs, and how the fleet's makeup and size changes over time.

Q. Are there any other analytical tools that are part of the fleet cost tool?

A. The Acquisition Purchase Plan tool is designed to provide detailed cost information for a specific unit, including total operating cost, as well as average costs over time for specific specs. In this analysis, the Company evaluates equipment count, total operating cost, average unit operating cost, median unit operating cost, and average unit age. Finally, the PowerBI tools can report a particular territory, city, spec, equipment count, and total operating cost for vehicles distributed throughout the Company's service area. Current Month Unit Locations reports the unit's location, displayed on a map, with circle size indicating high/low equipment counts and color indicating zone. Average Unit Age and Total Operating Costs are summarized in cards at the top of the page. This page allows the user to filter the Year, Usage Indicator, Rental Status, and Spec. The purpose of this tool

is to allow the user to use the filters to summarize equipment count, cost, and age by location.

Q. Why are these PowerBI tools appropriate for the Company to use?

A. Using the Company's own data, the information these tools provide is used to help the Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet Cost Tool data provides information from several perspectives that helps narrow the pool of vehicles identified by the Blended Factor for replacement. For example, the Blended Factor may identify many units within any given spec that are at or near the end of their expected life, but a further examination using this tool can help inform how the unit is performing in relation to other identical spec vehicles in the fleet from a cost perspective. If the unit has become uneconomical to operate compared to other vehicles in the same spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather than later. Conversely, a vehicle that has reached the Blended Factor end of expected life may still have years of economical service possible based on operating cost reported by these tools. This fleet cost tool also allows the Company's fleet management to understand how fleet costs have changed year-over-year, including the ability to examine costs of specific units to help inform if they are good candidates for replacement. The tool is intended to provide an overview of past fleet metrics, and helps to identify relationships between unit age, mileage, and operating costs. It also shows fleet age by spec which can be helpful when multiple units of the same spec were purchased in the same year. This is valuable information to consider when prioritizing the most appropriate vehicles to replace at any given point for the benefit of customers.

Q. What has the Company learned to date from using its fleet cost tool?

A. The fleet cost tool has allowed the Company to make informed decisions while reviewing units identified for replacement. This tool provides the Company with an at-a-glance total of overall costs of a particular unit. As the fleet team strategizes how and where to replace vehicles, the cost tool assists in framing how to best benefit the customer in the decision-making process.

As noted, the Blended Factor calculation is a starting point in the decision-making process, with the expectation that the list can be modified as further analysis proceeds. The cost tool facilitates a review of repairs and improvement costs associated with each vehicle that can extend its service life. For example, feedback sought and received from field personnel on the overall condition and serviceability of a truck can show that it should be kept in service instead of being replaced. This includes investments like engine or transmission rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require closer scrutiny when making purchasing decisions. This benefits the customer in that the Company gets as much service life out of units as is economically prudent.

C. Crewing Model Tool

Q. Please explain the Company's crewing model and crewing model tool.

A. As part of the second phase of its Fleet Replacement Planning Process, the Company's crewing model is used to calculate how many vehicles are needed based on the size of the workforce. This model incorporates all electric department vehicles and details about which employees are assigned to operate these vehicles. The electric departments include Customer Field Services, Electric Meter Operations, Low Voltage Distribution ("LVD"), and Substation Maintenance. These departments operate the following types of vehicles:

bucket trucks, digger derricks, service buckets, pickup trucks, and other support vehicles. The crewing model tool illustrates how many vehicles are needed and how many vehicles are available, giving visibility to gaps.

Q. What information does the tool show?

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between the actual number of vehicles at the location and the number of vehicles needed.

Q. Have there been recent updates to the LVD crewing model?

A. Yes, LVD crewing models have been updated to reflect most current up-to-date crewing practices for the tasks that need to be completed.

Q. How was this crewing model developed?

A. The Company's Electric Operations Department's workforce size and crewing influence the number and types of vehicles needed to serve customers. Crewing is determined by the work required and influenced by safety and policy procedures related to the work performed. The model also considers the particular requirements of the area the Company is operating in. For example, in regions with service centers that have less than six crews, the model drives a Trencher/Mini Excavator 2:1 ratio for a Line Worker in Charge. The ratio is 3:1 Trencher/Mini Excavator for most other service centers because most other service centers have more than six crews. In the crewing model, the Company uses standard crewing of the following truck-to-employee ratios:

- Electric LVD crewing consists of one Line Worker in Charge ("LWIC"), one Journeyman Line Worker ("JLW"), and one Apprentice to make one crew. Each crew is assigned a bucket truck and a support vehicle. The support vehicle

could be a digger derrick or a pickup. The current crewing model calculates vehicle needs according to the following ratios:

Vehicle Type	Model Ratio SC with less than 6 Crews	Model Ratio SC more than 6 Crews
Bucket Truck	1:1 LWIC to Bucket Truck	1:1 LWIC to Bucket Truck
Digger Derrick	2:1 LWIC to Digger Derrick	6+ 2:1 LWIC to Digger Derrick
Pickup	2:1 LWIC to Crew Vehicle	6+ 2:1 LWIC to Crew Vehicle
Trencher/Mini Excavator	2:1 LWIC to Trencher	3:1 LWIC to Trencher

- Employees in Electric Meter Operations, Customer Field Services, Electric Field Lab, and Substation Maintenance usually operate as single workers, rather than in a crew, meaning they have a 1:1 vehicle ratio.

Q. Why is this crewing model appropriate for the Company to use?

A. The crewing model is based on industry best practices and Occupational Safety and Health Administration ("OSHA") requirements.[1] To provide a safe, reliable, and cost-effective fleet, it is important that the Company's fleet be adequate in size to complete the established work plan, work safely, and adhere to OSHA requirements.

Q. What conclusions can you draw from the data shown in the crewing model tool?

A. The model shows that the quantity of production units (bucket trucks, digger derricks, and service bucket trucks) currently in the Company's fleet will continue to be evaluated based on established work plans and employees needed to perform the work (more information on how utilization data is calculated is provided in the next section of this testimony). The model can help identify surplus or deficiency of assets in each specific area and units that are down for repairs or regular maintenance. This visibility allows the Company to reallocate surplus assets to areas with deficiencies to ensure each area is adequately supplied based on the model. Backup vehicles must be ready to meet the needs of the crews as daily schedules develop, meaning that some additional vehicles may be needed

[1] 1926.960 - Working on or near exposed energized parts. | Occupational Safety and Health Administration (osha.gov): https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.960

on short notice. The Crewing Model allows for backup vehicle availability for such circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

The Crewing Model assumes the Company will onboard new workers or add replacement workers consistently and in a timely manner as work plans develop to drive the need for workers and as attrition rates affect the workforce. However, the Company does not always receive new vehicles at the same time new workers are onboarded. For this reason, it is possible that new vehicles will be received and paid for before workers are ready to use them, but those vehicles *will* be put into use once the planned hiring is complete. Utilization rates for vehicles may at times reflect this reality.

Q. What has the Company learned to date from using its Crewing Model?

A. The Crewing Model offers the ability to find gaps in available units, and much like a checklist, allows the Company to proactively prepare for any emerging vehicle needs based on how new projects and employees are planned or deployed. In this manner, the Crewing Model complements the other fleet tools the Company is developing by ensuring that units are allocated as effectively as possible before and after any new units are purchased. The customer benefits from this because the Company is constantly working to keep its fleet right sized, with as few redundancies as possible.

D. Fleet Utilization Tool

Q. Please explain how the Company captures utilization data for its fleet.

A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer or switching. Each installed Telematic device communicates, via cellular signal in real time, information about the asset status including the unit's exact Global Positioning System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is

considered in use for any given day when it has traveled five or more (5+) miles at any time or equipment that is in operation for thirty or more (30+) minutes per day. This captured data is then uploaded and compiled on a nightly basis into one tool that can then be used to run reports as needed to manage the operation. This data is compiled into a fleet utilization tool that can provide fleet use by zone, by vehicle type, or department and is used as part of the second phase in the Fleet Replacement Planning Process.

Q. How was this data process developed?

A. The electronic information captured by the Telematics system documents industry standard data points that are used to log key vehicle information. Since 1996, every vehicle manufactured in the United States has an On-Board Diagnostic ("OBD") port/interface that can easily be made accessible to Telematics systems and their associated electronic data gathering capabilities. The OBD system provides access to a vehicle's Electronic Control Unit, the main computer that controls vehicle engine, transmission, and other key vehicle functions. By connecting directly to the OBD of each vehicle, the Telematics system is able to collect the real-time information required to inform the Company to log the key data points required to document utilization.

Q. How is the Company's utilization data tied to the crewing model?

A. As explained in the crewing model section, vehicles are assigned in response to the requirements of the daily work plan and the employees needed to complete the work. Some types of vehicles, like bucket trucks, are used frequently for common field operations, whereas there are other types of vehicles that are highly specialized and designed for specific tasks that are not always required on a given day/night to serve customers but are no less crucial to properly service customers throughout the state. The Company's

utilization data also accounts for the downtime that equipment must undergo when receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and for the fact that some equipment must be available for on-call assignments and off-hour assignments.

Q. Why is this approach to utilization data appropriate?

A. By capturing real-time telematic data from each asset and compiling it in one dataset, the Company obtains the required raw data to detail the exact frequency, duration, and overall use of each asset, and this data is then searchable for reporting utilization rate purposes. Utilization data can illustrate where units may be underutilized. The customer benefits from this approach because the Company ensures that all vehicles and assets are tracked, monitored for maintenance and safety, and allows for the optimal cost-benefit relationship and return on investment for its fleet. This approach supports the analysis of what assets the Company needs to purchase to be sure that it is replacing vehicles at the end of their lifecycles, and to be sure that the Company is serving customers with safe, capable, and effective equipment.

Q. What conclusions do you draw from the Company's fleet utilization data?

A. The Company's utilization rate data informs us that a continual review of fleet equipment for under-utilized vehicles, what areas of the business they serve, and how that may impact the Company's ability to serve its customers, will be on an ongoing analysis. It is a key tool in determining why and where vehicles may be down (or showing lower utilization rates). For example, vehicles that are down for repair or waiting for parts are different from vehicles that are available but are not being used to serve customers when evaluating utilization rates. The Company analyzes its fleet utilization to determine if there are any

redundancies that can be dispositioned in the future, such as through attrition and reallocating to raise utilization to more optimal levels.

E. Benefits

Q. Please summarize the Company's Fleet Replacement Planning Process.

A. The Company's fleet consists of 7,607 units of varying specs utilized for specific tasks to serve customers, divided between the electric and gas sides of the business. Assets referred to as "common units" are utilized by various other departments within the Company to support business operations. The Company employs a Fleet Replacement Planning Process (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to determine, in the most cost-effective and efficient manner, which units to replace. The Blended Factor identifies a pool of assets to consider replacing based on the mileage and age of each asset. Fleet cost data helps refine the initial group of eligible vehicles by helping to identify units that have become more costly than their value, or inefficient to maintain in the fleet. By applying crew modeling and utilization analysis, the Company checks to ensure that crew sizes support the potential number of vehicles replaced or added and confirms that replacement assets are appropriate based on usage rates. Customers benefit from this overall process because the systematic efforts noted above are designed to replace and/or add fleet assets at the most beneficial time possible. Each step in the process specifically identifies which assets to add or replace, and the rationale and timing.

Q. What are the benefits of the Fleet Cost Tool for customers?

A. The tool helps the Company make decisions about which units should be replaced or kept by illustrating when the cost of maintaining the units outweighs the cost of a new unit, or investments made in units to keep them in service, which ultimately supports decisions

made in the Company's Fleet Vehicle Capital Replacement Plan. The tool allows for visibility of significant investments such as a new engine or transmission in a vehicle that could extend its service life. Customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

Q. What are the benefits of the Crewing Model for customers?

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be a good steward of the fleet, the model helps validate if additional units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

Q. What benefits does fleet utilization data provide for customers?

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right assets in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations. This is true for all fleet assets other than specialized equipment, which will appear underutilized and not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to ensure that the fleet is a safe and effective part of the service it provides.

The Company's ability to serve its customers reliably, efficiently, and to a high standard requires an equally capable fleet. By methodically incorporating utilization processes that monitor fleet assets, the Company can maintain its fleet to manufacturers' specifications, as well as addressing the periodic wear and tear that comes with operating

vehicles in often extreme conditions. Utilization data that monitors each type of vehicle can also assure that the Company is earning the best return on investment for the expected environment in which said vehicle is designed to operate. For example, the Company expects that investing in a sedan should provide a life expectancy of seven years and approximately 150,000 miles under normal service. Utilization for a vehicle of this type may differ as compared to a utility truck sent as needed to address concerns in the field or support customers as the need arises. However, for both types of vehicles, regular monitoring of utilization reports will help the Company plan for the replacement of each vehicle with regular use over time. Additionally, analysis of any under-utilized vehicles will inform decisions on how many future investments in that type of vehicle are made going forward. Customers benefit when the Company is making best use of its fleet to deliver service. Utilization data helps the Company right-size its fleet by identifying where additional units are needed to accommodate the Company's workforce, if there are any surplus units, and if existing units can be more effectively used by the Company, such as by moving units to a new location or new department.

Q. Have there been right sizing efforts that benefit the customer?

A. Yes. Since mid-2022, the Company has reduced its total number of units by approximately 450 units utilizing the tools described above. These right-sizing efforts benefit the customer by reducing overall costs through reductions and/or allowing a particular unit to be effectively utilized in support of serving customers.

Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit customers?

A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and replace vehicles in a cost-effective way by using qualitative and quantitative inputs to identify units for replacement, particularly by identifying those units with high maintenance costs and exhausted expected useful lifespans. Retiring and replacing those units in a systematic way is designed to keep maintenance costs down while ensuring that vehicles are available when needed to serve customers. The replacement planning process is a constantly self-evaluating cycle that relies on the data the fleet itself generates over time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs, and the local expertise to assist in prioritizing how the Company replaces units in the fleet. Customers benefit from this replacement planning process because the fleet is a crucial part of the overall service the Company provides. A replacement plan allows the Company to provide a safe, reliable, and cost-effective fleet to respond timely to utility outages, damaged utility service, utility service renewals, and new construction requests.

Q. Are there further benefits related to safety, quality, and the planet when determining the Fleet Vehicle Capital Replacement Plan?

A. Yes. By replacing vehicles in the fleet, newly introduced features from vehicle manufacturers are regularly incorporated into the Company's fleet, such as the following:

Safety-

- Backup sensors and rear-view cameras. This feature allows for safer backing, resulting in fewer rearward collisions, reducing vehicle and property damage, and increasing safety for the Company's customers and employees as well as collision avoidance and auto emergency braking, reducing collisions by advanced driver warning and applying brakes in advance of collision.

- Reduced stopping distance requirement from the Federal Motor Carrier vehicle safety standard for class 6-8 trucks. The standard distance required to stop a commercial vehicle was reduced, (National Highway Traffic Safety Administration 49 CFR Part 571, requiring a 30% reduction in stopping distance compared to currently required levels), which led to equipping trucks with larger braking systems to avoid collisions on buses and trucks manufactured on or after July 1, 2005.

- Light Emitting Diode ("LED") headlight technology. This allows a driver to see further down the road giving the driver more time to react to a situation. LED headlights also save money due to less frequent bulb changes, thereby reducing time under repair.

Quality-

- Materials to manufacture vehicles are continuously advancing. For example, the Ford F-150 body is now stamped out of military grade aluminum, making the truck lighter, which increases fuel economy. Another added benefit of aluminum bodies is corrosion resistance, meaning less time and money spent repairing corrosion problems.

- Over the last 10 years, diesel engine exhaust gas recirculation coolers have improved, eliminating the need to replace them as frequently. This saves approximately $4,000 per replacement, where such replacements occurred about every two years.

Planet–

- To align with National Highway Traffic Safety Administration's corporate average fuel economy standards, new vehicles are becoming more fuel efficient to align with their regulations. When replacing units within an appropriate lifecycle, the Company has an opportunity to purchase more fuel-efficient vehicles, including fully electric and plug-in hybrid vehicles where appropriate, ultimately reducing the Company's carbon footprint.

- Fossil fuel powered vehicles may be replaced with an EV if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

Fleet Bucket Truck Remediation

Q. Was there a fleet event that affected expenditures proposed in this case?

A. Yes. As described below, the Company removed 88 bucket trucks from service in response to a safety incident with a bucket truck.

Q. Please describe the sequence of events that occurred on February 5, 2026 bucket-truck incident.

A. On February 5, 2026, at approximately 9:00 AM, a catastrophic boom tip failure occurred on a 2015 Terex TL-55 bucket truck in Flint. The bucket, with two men in it, partially detached and overturned, suspending the linemen in mid-air attached to their safety tethers. Fortunately, no serious injuries occurred due to proper fall protection.

Q. What immediate actions did the Company take?

A. The Incident Command Structure was enacted and 88 bucket trucks were removed from service to prevent any further safety incidents and determine the best course of action. To maintain continued and seamless operations safely, the Company secured 88 rental units as a short-term solution to the gap in units available and as a mitigation measure to continue proper service to customers. By February 8, 2026, non-destructive testing was performed on seventy-eight units. Twenty-nine units failed the test and are not considered safe for re-deployment.

Q. Did the booms that failed satisfy the Blended Factor threshold required for replacement qualification?

A. Out of the 88 units that were removed from service, 85 units already reached the Blended Factor threshold for replacement consideration. For the remaining three units, their blended factor is already very close to 0 and projected to become positive by the next calendar year. As noted earlier in my testimony, a Blended Factor indicating an above zero percentage qualifies a unit for replacement consideration.

Q. What is the reason that the 85 units, which have satisfied the Blended Factor threshold replacement qualification, have not yet been replaced?

A. The Company's electric fleet replacement plan is based on historical plus inflation cost amount of approximately $20 million. As such, there is a limited number of 1:1 replacement units possible, even though there are more units that qualify for replacement. This leaves only the highest priority trucks selected for replacement: the highest mileage and poorest condition units in the field in some instances. Further, at current replacement levels, the overall average age of the fleet is trending older.

Q. What are the short-term countermeasures and associated costs?

A. The Company is using single-axle rental units averaging between $4,000-$5,000 per month per unit, with an associated $17,000 in approximate annualized costs for maintenance per unit. Reduced productivity and the need to operate some disabled tandem units as tow support have increased costs until purchased replacement units can arrive. Total incremental O&M expenses for 2026 are approximately $1 million.

Q. Are rental trucks a suitable solution as a long-term strategy?

A. No. While rentals are part of the overall fleet strategy, the Company does not rely on rentals for long-term deployment. Over a relatively long period of time, a rental unit is an inefficient solution because of their generic configurations and discrepancies with Company fleet standard specifications. For example, for large bucket trucks, the rental market generally stocks primarily single-axles leading to limited availability of tandem axles. Michigan axle loading laws cap the permissible weight on a single axle to 18,000 lbs. This configuration hurts productivity because of not being able tow equipment and payload capacity limitations. Such limitations require additional trips and vehicles to

deliver tools and materials to job sites at added time and costs (i.e., labor and fuel). As such, compared to a purchased unit, rentals are a compromise that is only meant to fill the gap in the short term.

Q. What long-term remedial actions is the Company taking?

A. The Company plans to procure 83 new bucket trucks at an optimized "Stock+" specification. Five of these 88 trucks are already committed at the current spec and are in the replacement schedule. All 88 new trucks feature more robust stacked-boom designs, shorter lead-times, and improved standardization. The Company will be spending approximately $33.150 million in the 12-month period ending December 31, 2026, on additional funding to replace the bucket trucks removed.

Q. Is safety a key factor behind the decision to replace the affected units?

A. Yes. Workforce safety is a primary driver in the decision to replace these units. Although factors such as blended factor data, age and condition, rental constraints, productivity losses, barriers to work plan execution (including impacts on reliability and service quality), and increased costs affecting customer affordability all support replacement; they are not the sole considerations. Notably, a unit of this boom model design failed in 2017, as discussed in greater detail below. Given the pattern of failures, culminating in the most recent catastrophic event that placed workers at significant risk, safety considerations ultimately predominate in the replacement decision.

Q. Why is it not feasible to exchange the booms and maintain the existing units in operation?

A. The majority of the 88 downed units are among the oldest and most degraded in the Company's fleet, averaging approximately $55,000 per year (based on the 2024-2025

actual costs) in maintenance costs before any boom replacement. Boom replacement itself would cost about $60,000 per unit, making it an expensive equipment investment for trucks that are or will soon be well past their useful life. This results in a poor return on investment, limits the Company's ability to execute its reliability work plan, and undermines long-term customer affordability. As these units continue to age, maintenance costs are expected to increase further, with major component repairs and body corrosion becoming cost prohibitive. See Confidential Exhibit A-146 (JJJ-5).

Q. Why did the Company not test the affected units and keep them in service?

A. The affected units have a telescopic, articulating boom design that allows flexible movement in tight spaces. However, this additional flexibility comes with a compromise. These boom types are a complex design with several moving parts and additional wear points. While telescopic, articulating booms have use cases (i.e., in cities that limit where and how the truck can stage for a job), there are other simpler, more stable designs like stacked booms. Also, telescopic, articulating booms stow in distinct ways and may generate uneven forces if the locking mechanism is improperly adjusted. When out of adjustment, the lock permits excessive movement during road travel. The Company has utilized several boom manufacturers with varying designs, each operated and maintained according to manufacturer guidelines. However, only this specific manufacturer and model have exhibited this type of failure. Notably, the Company experienced a previous non-catastrophic boom failure with another Terex unit in 2017. In that case, a crack identified during inspection led to an engineered solution developed by the manufacturer and implemented across all similar units. Weekly visual inspections were conducted for over

a year without further failures, followed by monthly inspections for an additional year, before inspections returned to the manufacturer's recommended 60-day interval.

Q. Does the Company have a plan for the disposal of the 88 bucket trucks?

A. Yes. The Company has removed the historical net book value of these trucks because it anticipates they will be disposed of prior to the start of the test year. The Company further proposes that any net gain from the disposition of these trucks, after considering disposal or other related fees, be recorded as an offset (i.e., a reduction to rate base) against the cost of the new vehicles as described in Company witness Hannah L. Patton's direct testimony. The Company will follow the current standard disposition process used for all fleet equipment at the end of their useful life. As of May 2026, the process has started and will continue with the Company's auction vendor, removing these units from fleet's inventory.

Q. Is replacement of the removed trucks with new purchases more prudent from a financial perspective?

A. Yes. If the existing trucks are retrofitted with new booms, the total projected costs, including boom replacement and installation, as well as maintenance and repairs, over three years to maintain these older vehicles in service are expected to exceed $28 million by 2028 (refer to Confidential Exhibit A-146 (JJJ-5)). This analysis presumes that the booms will be installed in 2026. Furthermore, it assumes a consistent and conservative average year-over-year maintenance cost increase per unit of 3% throughout the three-year modeling period, from 2026 to 2028. In contrast, the year-over-year rate of change for average maintenance cost per unit across these 88 units increased significantly, nearly doubling from 13% to 25%, a 92% increase from 2024 to 2025. A similar trend was observed when examining actual costs from 2023 to 2024, which increased from 7% to

13%, representing an 86% rise. This indicates a year-over-year acceleration that is expected to persist, even though the Company's projections reflect a moderate 3% annual change for the period 2026–2028. Nevertheless, under this three-year projection, the scenario rapidly approaches a breakeven point when comparing the estimated $28 million to the $33.15 million associated with the new purchase decision. In summary, new trucks typically incur substantially lower annual maintenance costs, benefit from manufacturer warranties, and significantly mitigate financial risk.

Q. Of the 88 affected units, most of the annual maintenance costs are primarily repair costs over any other maintenance costs. Please explain.

A. As indicated in Confidential Exhibit A-146 (JJJ-5), repair expenditures accounted for 81% of total maintenance costs in 2023, increased to 82% in 2024, and further rose to 84% in 2025. In our modeling, the Company conservatively flatlined the 84% from 2026-2028 (as actuals are unknown). In other words, the majority of maintenance expenditures are directed toward keeping older trucks operational, with most funds allocated to vehicles that have already been in service for an average of 10 years. It is essential to assess the proportion of repair costs relative to the overall maintenance expenditures, as well as to monitor their trends over time. These dollars do not represent enhancements, upgrades, or efficiency improvements. Rather, these costs directly represent the activities necessary to keep these degraded units operational. Additionally, it is important to recognize that repairs are inherently less predictable than routine preventative maintenance, which can result in expensive repairs such as engine or transmission replacements, particularly in older vehicles. Long, complex repairs are not only costly but disruptive to operations and negatively impacts the ability to serve our customers.

Q. What are the main drivers of the rising maintenance costs?

A. As is often the case with trucks approaching or surpassing the ten-year mark in service, major component failures like hydraulics, engines, and transmissions contribute to the high cost of maintaining older equipment. As these units approach 13 years of service, failures shift from predictable preventative maintenance work to unpredictable expensive repairs.

Q. In addition to co-worker safety, financial prudency, and customer affordability, how do these purchases benefit the customer?

A. The Company's trucks are essential assets that facilitate the execution of the Company's workplans and serve as the primary equipment for the electrical crews. Absent reliable trucks with high uptime, productivity may suffer and work order schedules are delayed or not able to be completed. This can lead to reduced capacity to serve customers, including timely outage restoration during storms and other service interruptions. Emergent repairs on older units have a higher probability out of service for longer periods of time, especially those with major repairs like engines or transmissions.

Additionally, these trucks are a critical part of the Company's Reliability Roadmap that commits to improving reliability and performing service restorations for all customers in less than 24 hours, even after severe storms, infrastructure upgrades, and grid modernization plans. It is critical that the Company's fleet is well-positioned to provide these crucial services and grid upgrades now and into the future for the benefit of our customers.

Q. What does this incident reveal about overall fleet health?

A. As discussed earlier in my testimony, nearly all the bucket trucks that were removed from service following the boom tip failure were already at the threshold for replacement. It

reveals that, at current replacement rates, fleet acquisitions cannot replace units at a rate to keep pace with the overall aging of the fleet. Further, actual inflation in the commercial vehicle market has eroded purchasing power. As the Company increases staffing to execute the MPSC-approved Reliability Work Plan, trucks and equipment must keep pace. Without an accelerated replacement strategy that lowers overall fleet age, additional failures could become more likely over time. Lastly, safe, reliable trucks that have high availability enable the workplan itself and are not separable from it. It is the necessary tool that allows the work to be performed. This drives the Company's stated objectives of lowering outage minutes and improving customer services levels in the most economically beneficial way possible.

Q. What other concerns does the Company have regarding the boom tip failure incident?

A. The Company holds the safety of all workers as a top priority. The work performed by employees utilizing bucket truck booms is especially critical to the service provided to customers and must be performed with the utmost safety of the teams utilizing bucket trucks. The Company's immediate and long-term response to the boom tip failure seeks to assure the safety and well-being of the crews servicing customers by providing the most capable trucks and equipment possible.

Q. Are there any other bucket trucks exhibiting similar potential safety concerns as it relates to booms?

A. Yes. The Company has also removed 26 spec 64 and six spec 65 bucket trucks from active status as a precaution after inspections revealed welding issues triggering safety concerns on a 2015 Terex truck in its articulating arm for bucket deployment. The factors contributing to these safety concerns is the aging of the fleet, as these particular units are

also among the oldest service bucket trucks in the Company's fleet. The Company is still working through a root cause analysis to decide what the best course of action is.

FLEET ELECTRIFICATION

Q. Does the Company plan to continue purchasing EVs for its internal fleet?

A. Yes, as part of the Company's continued commitment to sustainability and operational efficiency, the Company is evolving its internal fleet electrification strategy. While the original goal targeted 30% fleet electrification by 2030, and electrifying all light duty units thereafter, the Company is now shifting toward a more pragmatic, market availability driven approach. Moving forward, the Company will prioritize and target 1-for-1 electric vehicle (EV, electric Power Take Off Units on bucket trucks ("ePTO"), and Plug-In Hybrid Electric Vehicle("PHEV")) replacements where a clear business case supports the transition from an internal combustion engine ("ICE") vehicle. This strategy allows fleet to focus on electrifying vehicles or battery powered ePTO that deliver measurable value, whether through reduced emissions, lower operating costs, or improved performance—while maintaining flexibility across our diverse fleet needs. The previous approach would have required purchasing EV units at a rate higher than the 1:1 purchase plan allowed.

Q. How many EVs does the Company have in its internal fleet currently?

A. The Company's fleet currently operates 289 EVs, representing approximately 5% of powered units in the overall fleet.

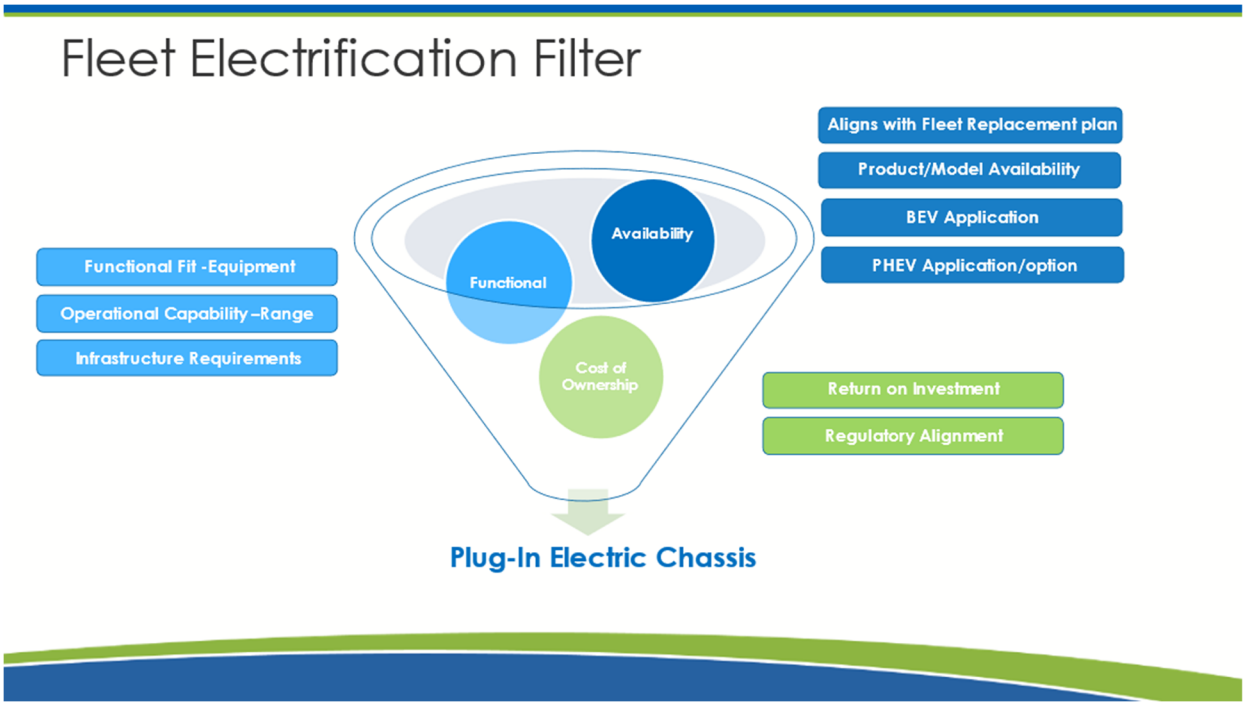
Q. How does the Company determine opportunities to replace ICE vehicles with EVs?

A. The same replacement process, as discussed earlier in my testimony, is used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under

this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. The Company also uses how many miles an ICE unit the EV might replace to determine if there could be any range challenges were an EV to be used instead. As the Electrification Filter shown below shows, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and similar or lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.

Q. Does the Company use telematics data to help determine which ICE vehicles are most appropriate to replace with an EV?

A. Yes, the Company uses data captured by telematics devices on ICE vehicles to help forecast mileage range requirements where an EV is being considered as a replacement for an ICE vehicle.



Q. In what ways are EVs more beneficial than ICE vehicles?

A. Most of the benefits gained from utilizing EVs or electric battery-assisted ePTO systems arise from the changeover to electricity as the main source of energy, instead of gasoline or diesel fuels and petroleum-based maintenance materials. Electric motors require much less powertrain maintenance and repair, resulting in reduced maintenance costs, which is one of the key benefits of electrifying fleet units. In ePTO systems, stored energy is used to shut down diesel/gasoline engines for periodically, saving fuel and engine wear. Generally, a fully EV (battery) powered vehicle can also have up to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors operate with less friction and more efficient use of energy. Many ICE vehicle parts require frequent and costly maintenance routines. Further, up to 65% of the heat energy produced by an ICE is wasted, requiring cooling systems which are prone to wear and eventual failure.

Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal EVs?

A. Yes. Per Case No. U-20963, the Company has partnered with CALSTART, a national non-profit company with over 30 years' experience in the private and public sectors with a proven track record working with over 280 member companies and agencies to build business cases for clean transportation technology adoption. CALSTART is a nationally respected team of fleet electrification experts who were selected by the Company via a competitive Request for Proposal. CALSTART has completed numerous fleet electrification assessments for external customers, in addition to the Company's. The assessments analyzed the Company's light duty fleet vehicles, by location, and daily miles

driven to provide approximate load demand by location. EV location determination helps in understanding potential carbon emission avoidance and cost benefit analysis.

Q. Are there other vehicle electrification tools available to reduce fossil fuel consumption in ICE vehicles?

A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to reduce fuel consumption by reducing idle hours required to operate ancillary equipment such as a boom on a bucket truck. By employing a plug-in battery and electric motor, for example, ePTO units can power hydraulic systems for short periods, reducing fuel consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an idling engine off, and a battery-powered motor then powers the hydraulics needed to position the boom and bucket, as well as powering the climate control system in the cab. As a result, the bucket truck will operate quietly while the operator performs work near a customer's home because the sound of an idling diesel will not be present while the ePTO system is engaged. The Company already employs this technology on some bucket trucks to help reduce idling hours while operating booms and cabin climate control. Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions, as well as diesel particulates.

Q. Are there other associated projects being planned to support vehicle electrification efforts?

A. Yes. The Company must plan for charger installations, and the increased electric load demands at service centers to charge the EVs.

Q. How does limited availability of EVs affect the Company's goal?

A. The Company's ability to increase the number of EV units in the fleet remains flat through 2028. At this time, there is limited market availability for suitable EVs that meet the Company's needs. This could prevent the Company from ordering a suitable number of EV units needed to affect a more linear glidepath toward the 2030 goal. Also, the EV opportunities identified in the Purchase Plan averages about 20 to 25 units per year. If the Company continues to purchase EV units at this pace per year, the goal to electrify 30% of the fleet will not be met by 2030.

Q. Has the Company completed an assessment of light duty units coming up for replacement in the Purchase Plan?

A. Yes. Per the order requirements in Case No. U-21870, the Company has assessed the potential viability for electrifying already scheduled light duty vehicle replacements in the purchase plan. The assessment and data can be found in Exhibits A-149 (JJJ-8) and A-150 (JJJ-9), respectively.

Q. What conclusions do you draw from the assessment?

A. The assessment determines that, although the Company continues to explore feasible options for fleet electrification, any implementation must align with operational requirements and adhere strictly to the approved vehicle replacement plan.

Q. Has the Company conducted any other studies related to fleet vehicle purchases in future years?

A. Yes. Per the order requirements in Case No. U-21870, the Company examined the potential impact of reduced vehicle purchases, utilization rates, and fleet aging. The

analysis and associated data can be found in Exhibits A-147 (JJJ-6) and A-148 (JJJ-7), respectively.

Q. What conclusions do you draw from the analysis of reduced vehicle purchases in future years?

A. The study concludes that overall average vehicle utilization is increasing even as the average vehicle age is trending older, increasing in age over the study period. Lowering purchases will result in an even older fleet. Further, and crucially, the impact of an increasingly aging fleet raises risk of escalating maintenance and repair costs, safety concerns as well as potential for more disruptive unplanned capital requirements in the future.

Q. Are there any other fleet-related information gathered as a result of the order in Case No. U-21870?

A. Yes. The Company has included more details regarding existing vehicle usage by specification. The data can be found in Exhibit A-151 (JJJ-10).

Q. What EV units does the Company plan to purchase for the test year?

A. The Company is planning to add 10 Job Site Energy Management System ("JEMS") ePTO on 10 spec 64 bucket trucks.

Q. What associated infrastructure support will the EVs planned for the test year require?

A. The ePTO units will require chargers installed at their planned respective headquarters to support their charging requirements.

Q. How could ePTO systems in the Company's fleet benefit customers?

A. The Company seeks to reduce its overall operating costs, wear and tear, and carbon dioxide emissions from the operation of the planned bucket truck purchases in the test year. By periodically shutting down the truck engine to use battery power to operate the boom bucket, ePTO bucket trucks can reduce total lifetime idle time that can lead to engine replacements and maintenance. Bucket trucks equipped with ePTO systems also offer carbon reductions, and quieter residential street operation as well. The Company's customers can benefit from the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall operating costs related to operating its internal fleet.

FLEET SERVICES CAPITAL SPENDING PROJECTIONS

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (JJJ-1), Schedule B-5.1.

A. Exhibit A-12 (JJJ-1), Schedule B-5.1, provides electric Fleet Services capital spending, broken down into six capital spending categories: (i) Fleet Vehicle Capital Replacement; (ii) Fleet Vehicle Capital Replacement – Additional; (iii) Fleet Vehicle Electrification; (iv) Fleet Expansion; (v) Fleet Business Partner Funded; and (vi) Fleet Tools - Garage. Exhibit A-12 (JJJ-1), Schedule B-5.1 provides these capital expenditures with actuals for the 12 months ended December 31, 2025; projections for the 12 months ending December 31, 2026; 4 months ending April 30, 2027; 16 months ending April 30, 2027; and projections for the 12 months ending April 30, 2028, which is the test year in this case. For the historical year, 12 months ended December 31, 2025, the Company incurred Fleet Services capital expenditures in the amount of $23.915 million. The Company is projecting electric Fleet Services capital expenditures to be $65.711 million for the 12

months ending December 31, 2026; $10.557 million for the 4 months ending April 30, 2027; $76.268 million for the 16 months ending April 30, 2027; and $26.633 million in the projected test year ending April 30, 2028, as set forth in Exhibit A-12 (JJJ-1), Schedule B-5.1, page 1, line 7 columns (b) through (f), respectively.

Q. Are there any contingency costs included in the Company's projected Electric Fleet Services capital expenditures?

A. No.

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Capital Replacement - Additional spending?

A. Details of the Fleet Vehicle Capital Replacement Plan are included at Exhibit A-144 (JJJ-3).

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending?

A. Fleet vehicle electrification expenditures include the offset cost of ten (10) Altec JEMS ePTO systems in spec 64 bucket trucks.

Q. What types of expenditures are included in Fleet Business Partner Funded?

A. Fleet Business Partner Funded expenditure includes ten equipment trailers.

Q. What types of expenditures are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment to properly and safely service and repair fleet vehicles, equipment, and trailers. This is described in detail later in my direct testimony.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (JJJ-1), Schedule B-5.1?

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company breaks out these cost categories by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2021 through 2025 as a percentage of total Transportation Equipment investment over that same period. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e. contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (JJJ-1), Schedule B-5.1.

A. <u>Fleet Vehicle Capital Replacement Plan</u>

Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this case?

A. As shown in Exhibit A-12 (JJJ-1), Schedule B-5.1, page 1, line 1, the Company is proposing to spend $20.359 million in the 2026 bridge year; $3.235 million for the 4 months ending April 30, 2027; $23.594 million for the 16 months ending April 30, 2027; and $20.868 million in the 12 months ending April 30, 2028 test year on Fleet Vehicle Capital Replacement Plan spending.

Q. How did the Company determine its 2024 through 2027 Fleet Vehicle Capital Replacement Plan for the instant case, including the appropriate level of investment?

A. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2024 through 2027 at historical spending levels, adjusted for inflation, based on what the Commission has previously approved for "lifecycle replacement spending." By remaining at this level for 2025 through 2028, the Company is demonstrating its commitment to keeping costs affordable for customers.

Q. How did the Company develop the list of vehicles that is projected to be purchased in years 2025 through 2028 of this case?

A. The specific units that the Company plans to purchase 2025 through 2028 are also shown in Exhibit A-144 (JJJ-3). The Company produced an initial list of vehicles for replacement using the Blended Factor algorithm described earlier in my testimony, with a spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet. This list was prioritized by the Blended Factor percentage to highlight vehicles that generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor calculation), which indicates that a vehicle has reached its expected life. Following the Blended Factor Analysis, as described previously in this testimony, the Replacement Plan filter included a review of market availability. By reviewing market availability, the Company can determine which replacement specifications can be expected for delivery through 2028. Vehicles that are likely not available for delivery in 2026 were not considered for replacement. To further refine the list of vehicles, standard crewing models were assessed. Though the Company will be continuing an analysis on right sizing, standard modeling helped guide the decision-making process.

Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement Plan for 2026 and 2027?

A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing how often vehicles are used, the Company selected vehicles with a higher utilization rate when compared to similar specifications. The Company further narrowed the initial Blended Factor-based list based on fleet stakeholders' input on condition. In this step, vehicles were assessed by age, mileage, and overall condition, and associated operating costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

Q. Does the Company anticipate variances in future fleet spending?

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

B. Fleet Vehicle Electrification

Q. In the projected test year, 12 months ending April 30, 2028, the Company is projecting an investment of $500,000 for battery powered ePTO systems. What is included in this amount?

A. As shown in Exhibit A-12 (JJJ-1), Schedule B-5.1, page 1, the Company is proposing to spend $500,000 in the 12 months ending April 30, 2028 test year on Fleet Vehicle

Electrification. This sum includes $500,000 for JEMS idle mitigation ePTO units on each of 10 bucket trucks (vehicle spec 64).

Q. Why are the expenditures presented for Fleet electrification appropriate?

A. Fleet requested expenditures for ePTO idle reduction units are effective tools in lowering idle hours, fuel costs, and tailpipe emissions on bucket trucks. The addition of these battery powered ePTO units will further the Company's efforts to reduce fuel and maintenance costs, as well as its overall carbon footprint.

Q. How do these capital expenditures benefit customers?

A. The vehicle electrification expenditure will benefit customers in several ways. EVs and plug-in hybrids are expected to lower the Company's overall fuel and maintenance costs as compared to ICE powered vehicles. The EVs proposed also could offer significant potential reductions in greenhouse gas emissions, increasing the Company's carbon avoidance efforts, while providing service to customers with less pollution at lower cost. Lastly, the units proposed for the test year will further the Company's learnings on EV best practices, planning, and deployment as it increases fleet electrification.

C. Fleet Expansion Spending

Q. Exhibit A-12 (JJJ-1), Schedule B-5.1, contains a line item related to Fleet Expansion expenditures for High Voltage Distribution ("HVD"). Please explain what this is.

A. The Company intends to make investments of $856,000 in the 12 months ending December 31, 2025, $10,905,000 in the 12 months ending December 31, 2026, and $18,139,000 in the 16 months ending April 30, 2027, to support workforce expansion efforts in Electric Operations. The purchases include pickup trucks with specific upfits that will be used by the Electric Operations substations to perform work related to HVD

operations. The purpose of this workforce expansion is to continue facilitating the Company's increasing investment in electric distribution infrastructure.

Q. Exhibit A-12 (JJJ-1), Schedule B-5.1, contains a line item related to Fleet Expansion expenditures for LVD. Please explain what this is.

A. The Company intends to make investments of $5,000,000 in the 12 months ending April 20, 2028 for thirteen (13) spec 64 bucket trucks. The purpose of this workforce expansion is outlined in the testimony of Company witness Jeffrey P. Dickey, pages 10 through 12.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. If the proposed capital expenditure amounts for expansion are not approved, the Company risks stranding labor as some members of the Company workforce that construct and maintain electric distribution infrastructure will be without equipment and vehicles necessary to perform the work.

D. <u>Fleet Business Partner Funded</u>

Q. In the 12 months ending December 31, 2025, the Company funded a business partner investment of $734,000. What is included in this amount?

A. As shown in Exhibit A-12 (JJJ-1), Schedule B-5.1, line 5, column (b), the Company invested approximately $734,000 for 10 reconductoring equipment trailers for Electric Support Services.

Q. How did you determine the level of spending needed for the business partner funded equipment?

A. The level of spending represents equipment costs including tax, title, license and delivery.

E. Fleet Tools

Q. What kind of purchases are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

Q. What level of expenditures is included in this rate case for Fleet Tools?

A As shown on Exhibit A-12 (JJJ-1), Schedule B-5.1, Company spent $271,000 in the 2025 historical year; $257,000 for the 12 months ending December 31, 2026; $88,000 for the 4 months ending April 30, 2027; and $265,000 in the 12 months ending April 30th, 2028 test year on Fleet Garage Tools. A further breakdown of Fleet Tools per year can be found on Exhibit A-145 (JJJ-4).

Q. Why are the expenditures presented for Fleet Tools appropriate?

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the task at hand. The tooling can be anything from diagnostic tooling, electronic service information, tool sets, or a new air conditioning recovery/recycle/recharge machine required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine, transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to maintain access to new vehicle models. Electronic service information is required to diagnose vehicle concerns and to follow the manufacturer's recommended repair procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring that high torque fasteners requiring very high torque applications are properly set and adjusted to manufacturer torque specifications to ensure safe repairs and inspections.

Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

Q. What benefits does this level of Fleet Tools spending provide to customers?

A. Across the state, the Company has 36 locations where fleet mechanics are permanently stationed to perform their daily work. The Company also has remote sites, training facilities, and jobsite reporting locations where repairs to vehicles and equipment are also performed. The projected Fleet Tools for 2026 spending is approximately $506,000 for the entire Company, or approximately $14,056 for each of the 36 locations where mechanics are stationed. The electric allocation of this total is approximately $257,000. Each year, the Company replaces and updates outdated or unrepairable shop equipment such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to customers of having tools in good order is less downtime for vehicles and reduced maintenance expenses because the Company is not solely reliant on outside repair shops to complete the work needed to keep vehicles active. Most repair and maintenance items are performed by the Company's in-house mechanics; therefore, it is imperative that the Company maintain a complete and updated inventory of tools to complete the work required.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

JON J. KOETJE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Jon J. Koetje. My business address is 700 East Sternberg Road, Norton Shores, Michigan 49441.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") where I am the Sr. Manager of Engineering, Procurement, and Construction ("EPC") Project Management for Enterprise Project Management ("EPM") Electric Supply – Operational Assets.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Science in Chemical Engineering from Michigan Technological University. I earned a Master Certification in Project Management from George Washington University. I am a certified Project Management Professional® and a licensed Professional Engineer in the state of Michigan.

In 1983, I began employment at Sun Chemical Corporation in Muskegon, Michigan as a Process Engineer eventually working my way up to Manager of Maintenance, Engineering, and Reliability. My responsibilities included overseeing the maintenance, engineering, and reliability departments for an organic pigments production facility. My duties included management of general maintenance activities, outage planning and execution, implementation of capital projects from inception through execution, start-up testing and commissioning, and management of reliability that included non-destructive testing and vibration analysis.

In 2005, I joined Consumers Energy in the Equipment Services organization, as a Sr. Engineer II, where I managed the implementation of capital projects at the D.E. Karn ("Karn") and J.H. Campbell ("Campbell") plants.

In 2008, I progressed to the position of EPC Project Manager II. My responsibilities in that position continued the management of capital projects at the Karn and Campbell plants.

Between 2013 and 2020, I progressed through the project management job family to the position of EPC Sr. Project Manager I, where I managed increasingly complex projects and eventually a group of project managers that managed a portfolio of projects at the Jackson Generation Station, Zeeland Generation Station, and Karn and Campbell plants. In 2020, Consumers Energy promoted me to Director of EPC Project Management – Fossil Generation where my duties include the management of capital projects for the fossil portfolio. Following a recent Company re-organization, my title changed to Sr. Manager of EPC Project Management for EPM Electric Supply – Operational Assets.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony concerning decommissioning, and ash disposal in the Company's 2024 Electric Rate Case, Case No. U-21585 and the 2025 Electric Rate Case, Case No. U-21870.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the actual 2025 expenses for the Karn Units 1 and 2 and Campbell Units 1, 2, and 3 decommissioning. In addition, my testimony presents updated projected decommissioning expenses for Campbell Units 1, 2, and 3

consistent with the projection presented in Case No. U-21585 as well as updated projected decommissioning expenses for Karn Units 1 and 2 in 2026.

Q. Please describe the generating units for which the decommissioning costs are being incurred.

A. Five coal-fired units have been approved for retirement. Karn Units 1 and 2 are two plants approved for retirement, as detailed in the Company's Commission-approved 2018 Integrated Resource Plan ("IRP") in Case No. U-20165. Campbell Units 1, 2, and 3 have also been approved for retirement, as detailed in the Company's Commission-approved 2021 IRP in Case No. U-21090.

Q. Please detail how your direct testimony is related to the direct testimony of other Company witnesses.

A. The projected spending associated with the Karn Units 1 and 2 Decommissioning and Campbell Units 1, 2, and 3 Decommissioning sponsored in my testimony are part of the overall generation asset strategy explained and sponsored by Company witness Mark E. Wittbrodt. In addition, Company witness Hannah L. Patton will discuss the regulatory asset treatment of the actual 2025 expenses for Karn Units 1 and 2 decommissioning, and Campbell Units 1, 2, and 3 decommissioning.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following Exhibits:

Exhibit A-152 (JJK-1)	Karn Units 1&2 Decommissioning Plan Expenditures; and
Exhibit A-153 (JJK-2)	JHC Decommissioning Plan Expenditures.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into two sections.

Section I will support the reasonableness and prudence of the actual 2025 decommissioning expenditures associated with Karn Units 1 and 2 as well as the updated actual and projected Karn Units 1 and 2 Decommissioning Plan Expenditures between 2024 and 2026.

Section II will support the reasonableness and prudence of the actual 2025 decommissioning expenditures associated with Campbell Units 1, 2, and 3 as well as the updated actual and projected Campbell Units 1, 2, and 3 Decommissioning Plan Expenditures between 2024 and 2030.

OVERVIEW

Q. Please explain why the Company is presenting its actual 2025 Karn Units 1 and 2 decommissioning.

A. The Commission issued an Order approving a settlement agreement in the Company's Electric Depreciation case, Case No. U-20849 ("U-20849 Settlement"). Paragraph 3(a) of the U-20849 Settlement provides for the recording of the Karn Units 1 and 2 decommissioning costs and the ash disposal costs for the Classic 7 and Karn Units 1 and 2 as spent, to a regulatory asset. Paragraph 3(a) further states that these costs may be requested for recovery in future base rate proceedings. Specifically, Paragraph 3(a) states:

> The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in

> future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

Q. Has the Company previously presented its plans for the decommissioning costs for Karn Units 1 and 2?

A. Yes. The Company originally presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21224. The Commission-approved settlement agreement in that proceeding ("U-21224 Settlement") approved the Company's plans for decommissioning costs for Karn Units 1 and 2 and coal ash disposal costs for Karn Units 1 and 2 and the Classic 7. Specifically, Paragraph 16 of the U-21224 Settlement stated:

> The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024.

Company witness Patton discusses the establishment of the regulatory asset for these costs and the proposed amortization in her testimony. The Company most recently updated its plans for the decommissioning for Karn Units 1 and 2 in Case No. U-21870.

SECTION I

Karn Units 1 and 2 Decommissioning Plan

Q. Why is the Company decommissioning Karn Units 1 and 2?

A. The settlement agreement approved by the MPSC in its June 7, 2019 Order in the Company's IRP, Case No. U-20165, approved the retirement of Karn Units 1 and 2 in

2023. This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the transition to net zero carbon emissions by 2040, and meet customer needs with 60% renewable energy and 20% clean energy sources by 2035 with an increase to 40% clean by 2040.[1]

Q. Please discuss the Company's Karn Units 1 and 2 decommissioning plan expenses.

A. The Company's decommissioning plan for Karn Units 1 and 2 originally presented in Case No. U-21224 and most recently updated in Case No. U-21870 was based on an evaluation of eight separate factors, including: (1) capacity replacement costs; (2) impact of recovery of undepreciated book value; (3) customer rate impact analysis; (4) non-economic variables such as portfolio balance, employment, and community impact; (5) effect on contractual fuel obligations; (6) near-term revenue requirements; (7) conditions of existing equipment; and (8) execution risk.

The Karn Units 1 and 2 Decommissioning Plan consists of multiple activities beginning with the development of a strategic plan focusing on: stakeholder engagement, workforce and community transitions, future use analysis, divestiture analysis, physical transition of systems to a de-energized state, remediation of regulated materials, physical demolition of the plant assets, salvage of scrap metals, remediation of all impacted areas, backfill of soils to acceptable engineered specifications, restoration focused on maximizing redevelopment opportunities, and completion of project closure to a brownfield standard.

[1] PA 235 of 2023 requires 80% of the Company's generation portfolio in 2035 to consist of clean energy resources. By 2040, PA 235 requires all of the Company's generation resources to consist of clean energy resources.

Q. What was the retirement date for Karn Units 1 and 2?

A. Consistent with the settlement agreement approved in Case No. U-20165, the retirement date was May 31, 2023. This date corresponded with the end of the Midcontinent Independent System Operator, Inc. ("MISO") 2022/2023 Planning Year.

Q. How were the cost projections in the Karn Units 1 and 2 Decommissioning Plan developed?

A. The projected costs consist of anticipated third-party costs as well as internal project administration costs. The projected costs were presented on Exhibit A-27 (JEB-1) in Case No. U-21224, the Company's 2022 Electric Rate Case filing, and have been updated in each of the Company's subsequent electric rate case filings (i.e., Case Nos. U-21389, U-21585, and U-21870). The most recent update was presented on Exhibit A-139 (JJK-1) in Case No. U-21870.

Q. What are the 11 major cost categories as outlined in the Company's Karn Units 1 and 2 Decommissioning Plan?

A. Exhibit A-152 (JJK-1), lines 1 through 11, column (a), identifies the 11 major cost categories associated with the Karn Units 1 and 2 Decommissioning Plan: 1) Utility Separation; 2) Decommissioning; 3) Abatement; 4) Demolition; 5) Asset Recovery; 6) Environmental; 7) Restoration; 8) Inventory Write Off; 9) Contingency; 10) Project Indirects; and 11) Interim Cost of Removal ("COR").

Q. What are the actual and projected costs as proposed in the Karn Units 1 and 2 Decommissioning Plan?

A. Table 1 below illustrates the total annual projected costs for the Karn Units 1 and 2 Decommissioning Plan based on the project schedule.

Table 1. Karn Units 1 and 2 Actual and Projected Decommissioning Costs ($000s)

Pre – 2022 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	Total Actual and Forecast
$6,970	$7,557	$25,694	$21,294	$16,418	$2,559	$80,492

Q. What were the actual 2025 costs for Karn Units 1 and 2 decommissioning?

A. Table 2 below illustrates the actual 2025 expenditures for the Karn Units 1 and 2 decommissioning.

Table 2. Karn Units 1 and 2 2025 Actual Decommissioning Costs ($000s)

Activity	Projected	Actual	Variance
Utility Separation	**165,408**	**-**	**165,408**
Decommissioning	**-**	**-**	**-**
Abatement	**-**	**1,308,633**	**(1,308,633)**
Demolition	**8,258,785**	**11,223,047**	**(2,964,262)**
Asset Recovery	**-**	**(6,193,456)**	**(6,193,456)**
Environmental	**-**	**753,864**	**(753,864)**
Restoration	**-**	**8,661,918**	**(8,661,918)**
Inventory Write Off	**-**	**-**	**-**
Contingency	**703,749**	**-**	**703,749**
Project Indirects	**2,682,058**	**663,886**	**2,018,172**
Interim COR	**-**	**-**	**-**
Total	**11,810,000**	**16,417,722**	**(4,607,722)**

Exhibit A-152 (JJK-1), lines 1 through 11, columns (d) and (e), further reflects these decommissioning expenses incurred in 2025 and a comparison to the projected expenditures presented in Case No. U-21870.

Q. How does the Company's decommissioning cost projection in this proceeding compare to the plan filed in Case No. U-21870?

A. The Company's decommissioning total project cost reflects a cost increase of $3,172,596 above the updated amount presented in Case No. U-21870 of $77,319,077. The updated decommissioning costs are presented on Exhibit A-152 (JJK-1), lines 1 through 11 in columns (b) and (c). The actual and projected costs have been updated to reflect field conditions encountered and additional costs incurred for restoration. I will describe each of the individual cost components and the basis for the actual costs and updated cost projections separately.

Q. Please discuss the basis for the change in the decommissioning plan for Karn Units 1 and 2.

A. Two main developments contributed to the projected cost of the decommissioning plan for Karn Units 1 and 2. The first of these are the field conditions encountered as the work progressed, particularly around the abatement and coal removal activities as well as the resulting changes to restoration. The second is the mitigation of risk as the project has progressed.

Q. Please describe the costs which are included in Exhibit A-152 (JJK-1), line 1, column (a): Utility Separation.

A. Utility Separation represents the construction and equipment costs that were projected to be incurred to separate the equipment and utilities that are common to Karn Units 1 and 2 and Karn Units 3 and 4. Performance of this work allows Karn Units 3 and 4 to operate independently after Karn Units 1 and 2 were retired on May 31, 2023.

Q. What were the actual 2025 Utility Separation expenses?

A. The Company's actual Utility Separation expenses for 2025 were $0. This represents the portion of the Utility Separation costs that were not capitalized and are considered COR. Costs that were capitalized are included in the testimony of Company witness Mark E. Wittbrodt.

Q. How does the Company's actual 2025 cost of $0 for Utility Separation compare to the projected 2025 expenses presented in Case No. U-21870?

A. The Company's cost projection for Utility Separation was $165,408 less than projected as the planned Utility Separation work was completed in 2024.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 2, column (a): Decommissioning.

A. Decommissioning represents the costs of both plant personnel and construction to drain equipment, clean equipment, and de-energize the plant in preparation for transition to Abatement, Dismantling, and Demolition ("AD&D"). This includes site separation costs to isolate the plant from energized sources as well as costs to provide temporary power for use during AD&D.

Q. What were the actual 2025 Decommissioning expenses?

A. The Company's actual Decommissioning expenses for 2025 were $0.

Q. How does the Company's 2025 actual cost of $0 for Decommissioning compare to the projected 2025 expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Decommissioning was as projected.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 3, column (a): Abatement.

A. Abatement costs represent construction costs to complete asbestos abatement and removal of other regulated materials from the plant. This includes transportation and disposal of asbestos and other regulated materials.

Q. What were the actual 2025 Abatement expenses?

A. The Company's actual Abatement expenses for 2025 were $1,308,633.

Q. How does the Company's 2025 actual cost of $1,308,633 for Abatement compare to the 2025 projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Abatement was $1,308,633 higher than projected due to adjustments in sequencing for abatement activities.

Q. Please explain what you mean by sequencing.

A. As a project progresses, the contractor may identify a different order or sequence of activities that is more efficient than originally planned. For example, the contractor may identify that continuing the Abatement work instead of starting demolition work will be more efficient and may push spending from one category to another during the execution year.

Q. Please describe the costs which are included in Exhibit A-152 (JJK-1), line 4, column (a): Demolition.

A. Demolition costs reflect the construction costs to completely dismantle and demolish the plant. This includes removal and recycling or disposal of non-metallic demolition debris.

Q. What were the actual 2025 Demolition expenses?

A. The Company's actual Demolition expenses for 2025 were $11,223,047.

Q. How does the Company's 2025 actual cost of $11,223,047 for Demolition compare to the projected 2025 expenses presented in Case No. U-21870?

A. Demolition expenses were $2,964,262 less than projected in 2025 due to changes in sequencing for the Demolition work in the schedule.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 5, column (a): Asset Recovery.

A. Asset Recovery reflects the sale and scrap of surplus inventory.

Q. What were the actual 2025 Asset Recovery credits?

A. The Company's actual Asset Recovery credits for 2025 were ($6,193,456).

Q. How does the Company's 2025 actual credit of ($6,193,456) for Asset Recovery compare to the 2025 projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Asset Recovery was $6,193,456 more credit than expected due to changes in sequencing in the schedule for Asset Recovery activities.

Q. Please describe the costs which are included in Exhibit A-152 (JJK-1), line 6, column (a): Environmental.

A. Environmental costs reflect the costs to remove and dispose of excess coal and impacted soil, close the bottom ash impoundment associated with Karn Units 1 and 2, and treat water removed for dewatering during Demolition activities.

Q. What were the actual 2025 Environmental expenses?

A. The Company's actual Environmental expenses for 2025 were $753,864.

Q. How does the Company's actual 2025 cost of $753,864 for Environmental compare to the projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Environmental was $753,864 more than expected due to changes in sequencing for scheduled Environmental activities.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 7, column (a): Restoration.

A. Restoration costs reflect the engineering costs to restore the property to final grade with controlled storm water management and establish vegetation.

Q. What were the actual 2025 Restoration expenses?

A. The Company's actual Restoration expenses for 2025 were $8,661,918.

Q. How does the Company's actual 2025 cost of $8,661,918 for Restoration compare to the projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Restoration was $8,661,918 higher than projected due to additional restoration required following the additional Environmental work in the coal yard completed in 2024 and 2025.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 8, column (a): Inventory Write Off.

A. Inventory Write Off reflects the book value of the remaining plant inventory assets that cannot be sold or redeployed.

Q. What were the actual 2025 Inventory Write Off expenses?

A. The Company's actual Inventory Write Off expenses for 2025 were $0.

Q. How does the Company's 2025 actual cost of $0 for Inventory Write Off compare to the 2025 projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Inventory Write Off was as projected.

Q. How does the Company's actual 2025 cost of $0 for Contingency compare to the 2025 projected expenses presented in Case No. U-21870?

A. There is a $703,749 decrease from the projection. Contingency funds were reduced due to the mitigation of risk or moved into other cost categories to cover realized risk.

Q. Will amounts labeled as contingency be recorded in the decommissioning regulatory asset?

A. No. Only amounts actually spent will be recorded to the regulatory asset. To the extent these contingency dollars are not spent, they would not be recorded to the regulatory asset and would not be requested for recovery.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 10, column (a): Project Indirects.

A. Project Indirects include Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative & General costs.

Q. What were the actual 2025 Project Indirect expenses?

A. The Company's actual Project Indirect expenses for 2025 were $663,886.

Q. How does the Company's actual 2025 cost of $663,886 for Project Indirects compare to the projected expenses presented in Case No. U-21870?

A. The actual 2025 expense was $2,018,172 lower than the projection due to decreases in Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative & General costs and staffing efficiencies realized during the work.

Q. Please describe the costs which are included on Exhibit A-152 (JJK-1), line 11, column (a): Interim COR.

A. Interim COR includes the COR portion of projects that were previously implemented but have not been recovered in the depreciation rate case.

Q. What were the actual 2025 Project Interim COR?

A. The Company's actual Interim COR expenses for 2025 were $0.

Q. How does the Company's actual 2025 cost of $0 for Interim COR compare to the projected expenses presented in Case No. U-21870?

A. The actual cost in 2025 for Interim COR was as projected.

SECTION II

Campbell Units 1, 2, and 3 Decommissioning

Q. Why is the Company decommissioning Campbell Units 1, 2 and 3?

A. The settlement agreement approved by the MPSC in its June 23, 2022 Order in the Company's IRP, Case No. U-21090, approved the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.[2] This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the journey to net zero carbon emissions by 2040, and meet customer needs with 100% clean energy sources by 2040.

[2] On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 ("DOE Order") requiring the Company to "take all measures necessary to ensure that the Campbell Plant is available to operate" through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted "sufficient time for orderly ramp down . . . consistent with industry practices." The Department of Energy has continued to reissue new orders extending the operation of the Campbell plant approximately every 90 days thereafter (the "202c orders"). Consumers Energy anticipates that these orders will continue into the foreseeable future. I discuss the impact of these orders on the Campbell plant in more detail later in my testimony.

Q. Please explain why the Company is presenting actual Campbell Units 1, 2, and 3 decommissioning in this proceeding for the period from January 1, 2025, through December 31, 2025.

A. The Commission-approved settlement agreement in the Company's 2021 IRP in Case No. U-21090 provided for the recovery of actual decommissioning spending for Campbell Units 1, 2, and 3. Specifically, Paragraph 5 of the settlement agreement stated:

> The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:
>
> > a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
> >
> > b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

In addition, collection of these costs through depreciation rates was terminated in the Company's electric depreciation case, Case No. U-20849. Company witness Patton discusses the establishment of the regulatory asset for these costs and their proposed amortization in her direct testimony.

Q. What information is presented on Exhibit A-153 (JJK-2)?

A. Exhibit A-153 (JJK-2) presents the Campbell Units 1, 2, and 3 actual decommissioning costs for 2025, and an initial estimate for the complete decommissioning of Campbell Units 1, 2, and 3.

Q. What amount of expense for Campbell Units 1, 2, and 3 decommissioning did the Company record to a regulatory asset during 2025?

A. The Company recorded a total of $4,503,092 of Campbell Units 1, 2, and 3 decommissioning expense to a regulatory asset during 2025.

Q. What is the current estimate for the complete decommissioning of Campbell Units 1, 2, and 3?

A. The current Class 3 budgetary estimate for decommissioning Campbell Units 1, 2, and 3 is $380,000,000, which is consistent with the estimate provided in the Company's 2025 Electric Rate Case U-21870.

Q. What activities were accomplished with the $4,503,092 expense for the period from January 1, 2025 through December 31, 2025?

A. Project expenditures in 2025 included $1,115,379 in Decommissioning cost, $1,228,917 for Project Indirect cost, $114,004 in Utility Separation, $2,000,400 in Demolition, $38,860 in Environmental, and $5,531 in Inventory Write Off.

Q. In your opinion, were these costs reasonably and prudently incurred?

A. Yes.

Q. What is the status of the Campbell Decommissioning Project in light of the Department of Energy's 202c orders that require the continued operation of the Campbell facility?

A. The United States Department of Energy has issued orders 202-25-3, 202-25-7, 202-25-9, and 202-26-16 requiring that the Campbell Facility continue to operate. Recent orders have indicated that the conditions requiring continued operation of the facility will continue for the foreseeable future, and that MISO and Consumers Energy should expect to continue to receive additional 202c orders requiring the continued operation of the Campbell facility. Therefore, the Campbell Decommissioning Project has been shut down and the project team members have been assigned other projects throughout the Company. There are some minor expenses that will be incurred in 2026 to complete engineering scopes of work, and complete modifications for the Lakeshore Administration Building.

Q. Are there any costs that have resulted from the issuance of the Department of Energy 202c Orders?

A. Yes, there is approximately $1,800,000 of spending that is a direct result from the Department of Energy's 202c orders. The expenses are primarily associated with making repairs to the system that were decommissioned prior to cessation and destructively tested hazardous materials, as well as engineering activities for the mothballing of the project for an efficient restart at a later date. These costs have not been included in this rate case and will be recovered as part of the cost of continuing to operate.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

KURT K. LAFRANCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Kurt K. LaFrance, and my business address is 1945 W Parnall Rd, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Director of System Protection and Controls, part of the Company's High Voltage Distribution ("HVD") Engineering organization.

Q. What are your responsibilities as Director of System Protection and Controls?

A. My responsibilities include oversight of the engineering of the protection system and the Supervisory Control and Data Acquisition ("SCADA") system of the Company's HVD, Low Voltage Distribution ("LVD") and Generation assets, as well as design of the protection and control systems of HVD assets.

Q. What is your formal educational experience?

A. I received a Bachelor of Science in Electrical Engineering *summa cum laude* in 2000 from Michigan Technological University, and received a Master of Science in Electrical Engineering in 2001, also from Michigan Technological University.

Q. Would you please describe your previous work experience?

A. I started my career with Consumers Energy in 2000 as an intern in Transmission Planning, working on stability studies for generator interconnection studies. Upon graduating with my master's degree in 2001, I was hired full-time to continue this work. When the Company sold its transmission assets in 2002, I moved into the HVD group of System Protection. I expanded my technical and supervisory skills over time, becoming a supervisor in 2007 and

Director in 2020. In 2007, I received a Professional Engineer license from the State of Michigan.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony provides an overview of the Company's HVD lines system, its HVD and LVD substations, and its Metro system; and associated capital investments to improve reliability and resiliency of those systems, while serving new customers to support economic development in the state of Michigan. I have organized my testimony as follows:

(i) A description of the Company's HVD lines system, HVD and LVD substations, Metro system, and System Protection assets, and the Company's strategy for investing in those systems;

(ii) A description of the HVD lines, HVD and LVD substations, and Metro capital programs and expenditures; and

(iii) A breakout of each of those capital programs' expenditures.

I also discuss and sponsor an exhibit explaining how the Company mapped substation and HVD line assets into voltage and other categories identified in the Electric Asset Categorization ("EAC") report used in the Cost-of-Service Study ("COSS") and discussed in more detail by Company witness Emily A. Davis.

Q. Are you the only Company witness addressing the Company's electric distribution strategy and investments?

A. No. Multiple witnesses are providing comprehensive support for the Company's electric distribution requests. Company witness Emily M. Duke will provide an overview of the Company's electric distribution strategy and will discuss electric distribution Operating and Maintenance ("O&M") spending. Company witness Jennifer M. Partlan will provide an overview of the Company's historical and planned capital investments in the LVD lines system. Company witness Scott A. McPhail will provide an overview of the Company's

historical and planned capital investments in the Grid Automation Program. Company witness Daniel A. Schmoekel will provide an overview of the Company's historical and planned capital investments in streetlighting.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-154 (KKL-1)	Consumers Energy Electric Asset Management High Voltage Distribution (HVD) Pole Inspection Specifications;
Exhibit A-155 (KKL-2)	Pole Inspection Plan by HVD Line;
Exhibit A-156 (KKL-3)	Summary Projected Electric Capital Expenditures for the Bridge Period 16 Months Ending April 30, 2027; and
Exhibit A-157 (KKL-4)	Summary Projected Electric Capital Expenditures for the Test Year 12 Months Ending April 30, 2028.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. How is your testimony organized?

A. Below is a Table of Contents which sets forth the subjects of my testimony.

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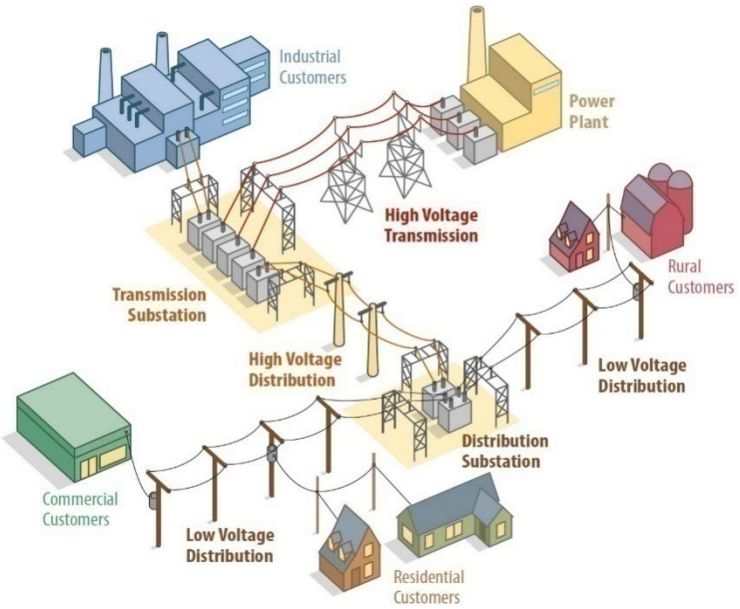
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I. EXECUTIVE SUMMARY

Q. What parts of the Company's distribution system will your testimony address?

A. As discussed by Company witness Duke, the Company's electric distribution system is comprised of HVD, LVD, and Metro assets. The HVD and LVD systems are shown below in Figure 1, illustrating how they fit into the overall grid. For purposes of this figure, Metro assets perform the same function as LVD distribution assets.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



My testimony will address the current health of the HVD lines system, HVD substations, LVD substations, the Metro system, and System Protection Relays, and explain needed investments in those systems to address asset health; improve system performance; and improve reliability for customers, particularly by mitigating the risk of large customer interruptions. These investments will ensure both the reliability and cost efficiency of the distribution system by proactively addressing, repairing, and replacing assets before they fail and ensuring a reliable and resilient system that can serve electric peak demand. This testimony and associated exhibits outline how projected investments in those systems deliver on the Company's Reliability Roadmap, which is included in this case as Exhibit A-95 (EMD-11). The capital investments outlined in this testimony are described in detail by sub-program and investment category, with discussion on the purpose of the program and the basis for the investment. Specific investments identified in the Reliability Roadmap include:

- Mitigating the risks from obsolete pole tops and deteriorated poles through investment in **HVD lines**;
- Mitigating the risks from deterioration through securing, inspecting, and upgrading **HVD and LVD Substations**;
- Mitigating the risks from deterioration through inspecting and upgrading the civil and electrical components of the Company's **Metro** assets;
- Enhancing and modernizing the protective system with **System Protection Relays**; and
- Ensuring the HVD System can serve electric peak demand, new interconnections, and support economic development through **HVD Load Growth & Interconnections**.

Please note that throughout my testimony I will often refer to the HVD lines system and HVD substations collectively as the "HVD system."

Q. Please provide an overview of the HVD system.

A. Consumers Energy's HVD system consists of HVD lines and substations that distribute electricity to its LVD substations. Information about the size of the system is shown below based on HVD line miles and number of substations. Additionally, the HVD system includes a system of protective relays, which I discuss separately in the section of my direct testimony on the System Protection sub-program.

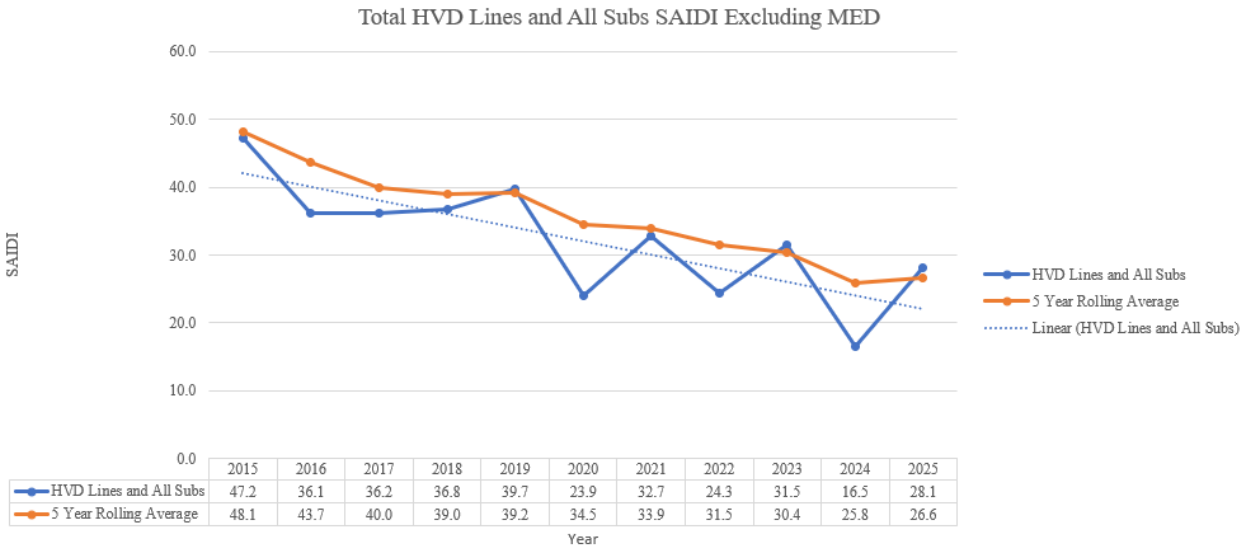
<table>
<tr><th colspan="2">HVD Lines System:</th><th colspan="2">HVD & LVD Substations:</th></tr>
<tr><td rowspan="2">4910 Overhead Miles</td><td>4640 Miles of 46kV</td><td rowspan="4">1140 Total Substations</td><td>144 HVD Subs</td></tr>
<tr><td>270 Miles of 138kV and 69kV</td><td rowspan="2">164 Strategic Electric Customer ("SEC") Subs</td></tr>
<tr><td rowspan="2">22 Underground Miles</td><td>18 Miles of 46kV</td></tr>
<tr><td>4 Miles of 138kV</td><td>832 LVD Subs</td></tr>
</table>

Q. Why must the Company make investments in the HVD system?

A. HVD lines and HVD substations are the backbone of the Company's distribution system, which means outages on the HVD system can lead to widespread interruptions for thousands of customers from a single incident. To mitigate against this risk, the Company must invest in the HVD system to ensure that the backbone remains resilient, able to quickly restore customers if outages occur, and to minimize the occurrence of outages in the first place. The Company has generally been successful at this over the years, meaning HVD assets do not usually contribute a major share of the Company's total System Average Interruption Duration Index ("SAIDI"). Indeed, historical investment levels in the HVD system have driven an improving trend line of overall HVD system performance in recent years.

Figure 2 below illustrates a gradual reduction in SAIDI. However, the risk of large HVD outages with a correspondingly high impact on SAIDI is always present if HVD assets begin to deteriorate. On average, when excluding major event days ("MEDs"), a single outage at an HVD substation or on an HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI and number of customers impacted. Without proper attention to the HVD system, SAIDI impacts will quickly increase, to the detriment of customers. A reliable and resilient system backbone is required to continue the Company's downward and improving trend in SAIDI performance.

FIGURE 2



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVD Lines and All Subs	47.2	36.1	36.2	36.8	39.7	23.9	32.7	24.3	31.5	16.5	28.1
5 Year Rolling Average	48.1	43.7	40.0	39.0	39.2	34.5	33.9	31.5	30.4	25.8	26.6

However, the asset health of many major components within the HVD system is deteriorating, with many of these assets well beyond their intended lifecycle. To ensure that this backbone infrastructure remains reliable and resilient, the Company monitors and assesses the asset health of HVD system components, so that areas of risk can be addressed proactively through investments. Investment in the HVD system, at the levels identified in the Company's Reliability Roadmap, is necessary to sufficiently reduce asset risk on the HVD system, ensure a resilient backbone, and to contribute to further reduced SAIDI.

Q. Can you provide specific recent examples of outages caused by HVD asset failures?

A. As the backbone to the distribution system, the HVD system often has built-in redundancies that prevent failure of a single element like a line or substation bus from causing a customer outage and increasing SAIDI. However, whenever a single element of the HVD system is out of service due to a failure or planned maintenance or construction, failure in another element can cause an extensive impact on SAIDI, with an operational risk to the rest of the HVD system that could cause overloads or cascading outages. Two recent events that illustrate this extensive influence of the HVD system are described below.

On March 19, 2026, an insulator at a substation near Kalamazoo failed, which caused the HVD substation to trip off. In normal conditions 5,565 customers would be directly impacted by this failure. However, a portion of the nearby HVD system was out of service for a construction project and this failure caused an outage to 10,266 customers for 115 minutes. On March 20, 2026, an insulator failure at a substation in Saginaw caused the HVD bus to trip off. In normal conditions, this would cause an outage to 10,856 customers. Due to a portion of the nearby HVD system being out of service for a construction project, this failure caused an outage to 15,696 customers for 62 minutes. These two incidents alone caused over 1 minute of SAIDI, which illustrate the major impact caused by even minor issues on the HVD system.

Failures of critical equipment like transformers or breakers can have an even larger impact on reliability, as these items can take weeks or months to replace due to the uniqueness of the assets and limited inventory availability. Such failures cause operating and outage risks on the HVD system for the duration of time they are out of service and are more difficult and expensive to replace in the expedited time required after an unplanned

failure. Therefore, it is critical to continue planned investment in the HVD system to reduce these risks.

Finally, failed assets can present safety risks to the public and to Company employees, particularly when they create situations where people can be exposed to high-voltage energized equipment. Investments to address asset health concerns therefore mitigate public safety risks.

Q. Can you further elaborate on how HVD lines and substation investments align with the Reliability Roadmap?

A. As Company witness Duke explains, the Reliability Roadmap includes investment in various areas, including the HVD system, necessary to reduce asset health risk to acceptable levels and reduce the risk of future outages. The investments identified throughout my testimony are aligned with those spending levels defined in the Reliability Roadmap, designed to ensure that the HVD system continues to provide a reliable and resilient backbone infrastructure, critical to supplying the LVD system. These investments will also help continue the downward trend in HVD SAIDI that the Company has seen in recent years, as shown in Figure 2 above.

Q. What is the Company's approach for investing in the HVD system?

A. The Company monitors the health of its HVD assets through a variety of data points from various maintenance and inspection programs. Through these processes, the Company determines the asset health risk for HVD assets, which informs investment decisions in HVD capital projects. These capital investments proactively address risk on HVD assets through repair, replacement, or upgrade prior to failure. A significant proportion of the Company's HVD investments are directed toward identified asset health issues and issues

identified during inspections; this is the basis for the Company's investment in its HVD reliability programs. All of these investments are intended to ensure the continued reliable and resilient operation of the HVD system. It is important to note that HVD system improvements may not always be captured in reduced SAIDI from existing levels, but there are still substantial customer outage minutes to avoid by preventing future failures from occurring. It is especially important to reiterate that risk of failure of specialized or unique equipment (such as transformers, breakers, and relays) within substations before failure occurs, due to the lead times and installation times required to replace such equipment after failure, as well as the risk of collateral damage occurring within the substation that could expand the impact of the failure to many more customers.

When needed, the Company also expands and/or modernizes the grid to serve growing loads from commercial and industrial ("C&I") customer base as they electrify their businesses. All HVD capital investments are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap.

Q. Why must the Company invest in LVD substations?

A. As with HVD system assets, LVD substations play a crucial backbone role in the distribution system, since they directly feed the LVD circuits that serve customers. While HVD substations often serve many downstream communities, LVD substations often serve a single community or a more focused local area, but this means that a given LVD substation can have a major impact on that single community. Outages on LVD substations lead to significant interruptions for customers when they happen, and as I discuss in my direct testimony, many of the Company's LVD substations have asset health risks that must be addressed to prevent those outages.

Q. Why must the Company invest in the Metro system?

A. The Metro system is dedicated to providing underground electric service in six key downtown areas in the Company's service territory and is critical for the economic health and development of the cities that it serves. As with HVD lines and with substations, the Company must ensure that the Metro system provides the needed electrical backbone for these downtown areas and must invest accordingly in order to support the asset health of the Metro system.

Q. How are the HVD lines, substations, and Metro system capital investments summarized in this proceeding?

A. The historical year is calendar year 2025. The bridge period consists of the 16 months beginning January 1, 2026, and ending on April 30, 2027. The test year is the 12 months beginning May 1, 2027, and ending on April 30, 2028.

Q. Please summarize the HVD lines, substations, and Metro system capital expenditure plan in this filing by historical year, bridge period, and test year.

A. The HVD lines, substations, and Metro system capital expenditures described in my testimony are summarized in Figure 3 below. Throughout my direct testimony, I will explain how these proposed investment levels will deliver meaningful benefits for customers through specific projects on the system.

FIGURE 3
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	$464,890,000	$434,899,000

Q. What specific HVD system, LVD substation, and Metro projects does the Company expect to invest in during the bridge period and test year?

A. Specific projects are identified in Exhibits A-156 (KKL-3) and A-157 (KKL-4). The exhibits include projects identified with scope, cost, location, benefit type, and benefits. The two quantitative benefit types are:

- Customer outage minutes avoided: Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.
- Customers impacted: Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."

Note that not all projects have quantitative benefits. Some projects may be completed for regulatory compliance, based on the Company's obligation to serve customers, or other reasons. Company witness Duke provides more details about how the quantitative benefits are calculated. Throughout my direct testimony, I will discuss the specific benefits of each investment sub-program.

II. HVD SYSTEM STRATEGY

Q. What challenges are faced by the HVD system?

A. The HVD systems are considered the backbone infrastructure of the electric distribution system because they connect the electric transmission system to the Company's LVD system. When outages occur on the HVD system, this backbone characteristic means interruptions to customers can be widespread and long in duration. To mitigate this, the HVD system needs to be resilient, which is why it is largely a looped system with built-in redundancies capable of either continuing service to customers or at least minimizing the number of impacted customers due to the failure of any single component. To maintain redundancy and ensure that this backbone infrastructure remains strong, the Company

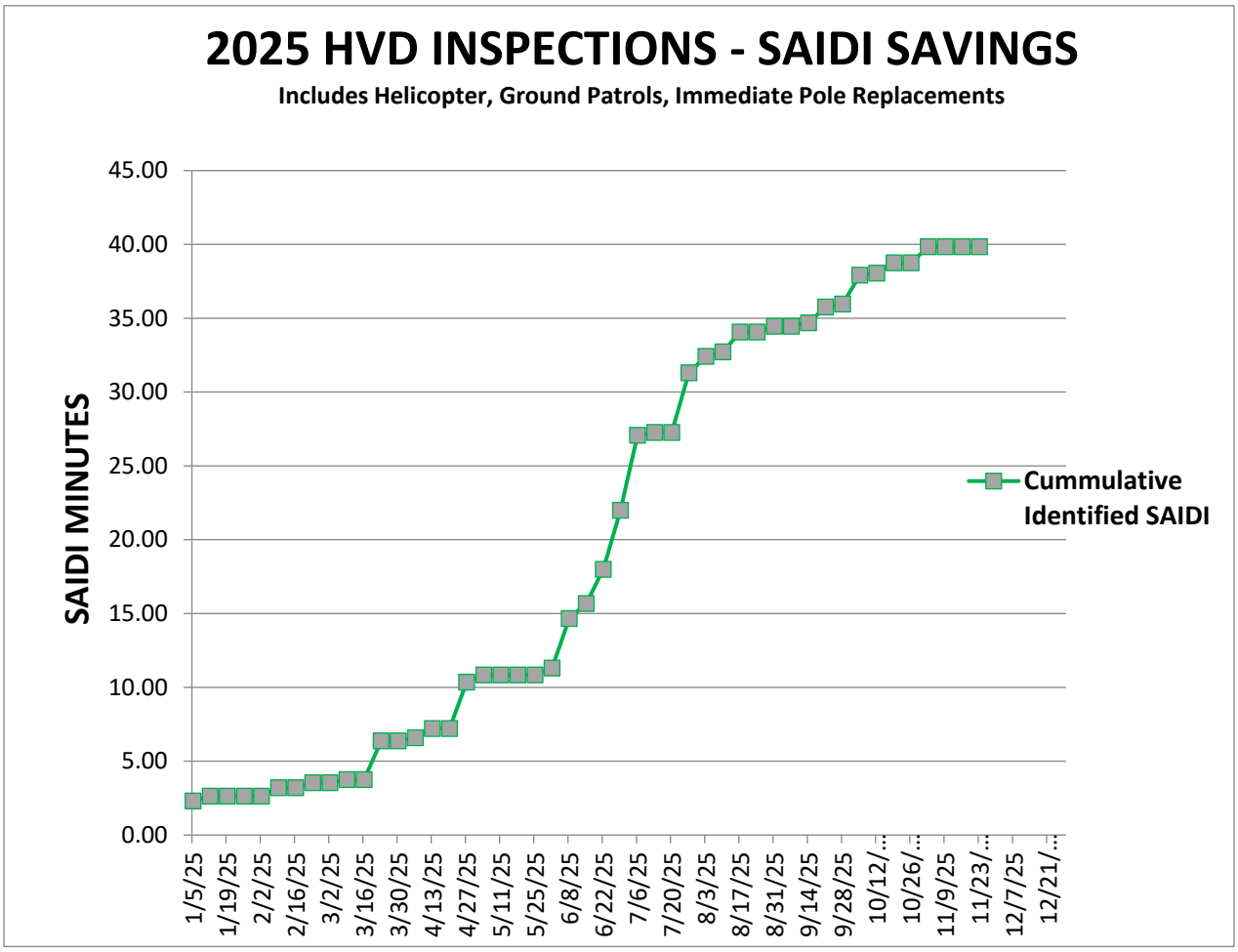
monitors and assesses the asset health of HVD system components, so areas of risk can be addressed proactively. This practice is discussed in the Reliability Roadmap.

Historical investment levels in the HVD system have improved the trend of overall HVD system performance as illustrated in Figure 2. However, significant variation in SAIDI contribution can also be seen from one year to the next, highlighting the significance of HVD system outages that do occur. The Company continues to face deteriorating asset health year-over-year for many of its HVD assets, which threaten their ability to continue to perform as a reliable and resilient backbone for the entire system.

Q. How is the Company able to substantiate that its HVD assets face declining asset health?

A. This is clearly supported by the findings from the Company's annual inspections, maintenance, and diagnostic tests of HVD assets that: a) identify anomalies that must be addressed prior to failure; and b) provide key insights into asset health and how assets are performing. In 2025, the Company's inspections identified anomalies that, if not addressed, would have resulted in 39.8 SAIDI minutes, as shown in Figure 4 below. This is also discussed in more detail later in my direct testimony when discussing the HVD Lines and Substations Demand Failures sub-program. In this figure, each data point reflects one week of activity. During each week, the Company mitigates any defects identified during inspections that would fail within months and cause interruptions to customers if not addressed (anomalies are typically addressed within one to two weeks of identification). The Company then calculates the SAIDI minutes that would result if the affected asset failed and caused interruptions to customers. The green trend line indicates the cumulative avoided SAIDI throughout the year.

FIGURE 4



For comparison, the equivalent avoided SAIDI from correcting anomalies was 16.8 minutes in 2023 and 25.3 minutes in 2024, indicating a worsening trend in HVD asset health, as the Company is finding more high-priority anomalies year-over-year. Historically, the equivalent amount was only about 10 avoided SAIDI minutes per year. This is one demonstration that HVD asset health is worsening, as the Company, through better use of technology and inspection techniques, is finding increasing levels of these narrowly avoided failures. Without increased proactive investment, anomalies will increase to a level where the Company cannot proactively mitigate failures, and significant interruptions to customers will result.

Q. How do inspections, maintenance, and diagnostic testing provide further insights into asset performance and health beyond these avoided interruptions to customers?

A. These key data points are collected and reviewed to build an asset health model that is used as a tool in determining capital investments and maintenance plans and establishing a general trend of asset health. The Company uses this asset health model to evaluate the assets on its system and identify all assets that face declining asset health, using a variety of data points to assess risk levels. The asset health model considers multiple inputs like asset type, manufacturer, condition, actual outages, and level of degradation collected about the asset during inspections, maintenance, and/or annual diagnostic testing to provide a holistic view of the asset's health. By applying this asset health model process to its HVD assets, the Company can document which assets face declining health and design projects to fix these issues; projects proposed in the instant case, particularly in the Reliability sub-programs, have been identified in this way.

It is important to note that the asset health model is meant to identify assets with elevated risk levels, but it is not meant to predict specific future failures and identify a date and time when they will definitely fail. The asset health model gives indications of where problems will likely occur so the Company can begin planning ahead and know where to focus its attention to address the biggest risks on the system.

Q. Please describe how the asset health model works in more detail.

A. As stated above, the purpose of the asset health model is to identify where the Company has elevated asset health risk so the Company can plan ahead to address issues. Planning ahead is essential because many projects have long lead times, and planning must begin multiple

years in advance; for many projects, the Company must first obtain rights of way and order long lead time materials well before design or construction can begin.

For HVD, the asset health model includes lines and substations and their components, as well as the relaying assets that are the subject of the System Protection sub-program discussed later in my testimony. For each type of asset, the asset health model incorporates critical asset factors such as inspection results and testing results, plus known manufacturing issues that affect certain types of equipment.

For each asset on the system, these inputs are used to generate an asset health score. An HVD line's asset health score combines multiple data points that include if it is a radial line or not, potential customer impact, type of conductor, configuration, number of trips, number of lockouts, red tagged poles, and victor insulators. Figure 5 below shows the point value assigned to each factor of a line segment that helps generate its overall health score, and Figure 6 shows a sample calculation of a line segment health score.

FIGURE 5
HVD LINE ASSET HEALTH WEIGHTING

Radial line	Points per mile	5
Customers	Points per 1,000	2
Obsolete conductor	Points per mile	5
Unshielded conductor	Points per mile	1
Top 25 contingency	Yes	0
Trip	Points per trip	1
Lockout	Points per lockout	2
Rush red tagged pole	Points per pole	2
Planned red tagged pole	Points per pole	1
Victor insulators	Point per insulator	0.3

FIGURE 6
HVD SAMPLE HEALTH SCORE BY LINE SEGMENT

Line Name	Total Point	Radial	Customer Impact	Obsolete Conductor	Unshielded	Victor Insulators	Red Tagged Poles	Lockout
Line Segment A	133	30	6	0	0	60	25	12
Line Segment B	100	0	10	50	10	0	30	0
Line Segment C	86.6	25	5	0	0	3.6	45	8

An HVD substation's asset health score combines the scores of multiple components within the substation. Figure 7 below shows an example of an asset health score for a substation, showing how multiple component scores total the station score. Figure 8 shows how transformer factors impact the total score for the transformer.

FIGURE 7
HVD SAMPLE HEALTH SCORES FOR SUBSTATIONS

Category	Points per Occurrence	Sub A	Sub B	Sub C
AC/FP/REC Wound	15	0	0	0
Insulation Degradation	10	1	1	1
Oil or N2 Leaks	5	1	1	0
Transformermer Internal Infrared	10	0	1	0
DGA Score	30	1	0	0
Brand A Bushing Issue	10	1	0	0
Brand B Bushing Issue	10	0	0	0
Infared Anomalies P1 or P2	10	0	1	0
Doble or Electrical Testing Issues	10	0	1	0
Transformer & Bushings Total		55	45	10
Reg/LTC Oil Analyses TOA Code 3/4	25	1	0	0
Infrared Anomalies P1 or P2	20	0	0	0
Reg/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3ph Reg or LTC Demand Order	10	1	0	0
Breaker Oil or SF6 Gas Quality / Leaks	15	0	1	1
Infrared Anomalies P1 or P2	15	0	0	0
Maintenance / Replacement Priority	10	0	0	0
Oil & Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSW/VSW Issues	15	1	0	0
SPT Watch List	10	2	1	1
Str & Concrete	5	1	0	0
Other	5	0	0	0
Infrared Anomalies P1 or P2	15	0	1	1
Operations Limiting Equipment	20	1	0	0
Station & Other Totals		60	30	30
Total Normalized Score		100	56.8	32.4
Gross Total		185	105	60

FIGURE 8
TRANSFORMER ASSET HEALTH WEIGHTING

Factor	% of Total Score
Manufacturer & Winding Type	15%
Insulation Degradation	10%
Nitrogen Gas or Oil Leaks	5%
Allis Chalmers Infrared	10%
Dissolved Gas Analysis	30%
Bushing Type	10%
Bushing Infrared Priority 1 &2 Issue	10%
Electric Testing Results	10%

Q. How are asset health scores used by the Company once generated?

A. In general, the Company uses asset health scores to rank lines and substations for the prioritization and development of projects. Since assets with higher scores are at greater risk of deterioration and failure, they are prioritized for projects to fix identified reliability issues. Asset health scores indicate not only *that* an asset faces deteriorating health, but also *what* is driving the issue, and this helps determine what kind of project is appropriate. For example, an HVD line may have a high score simply due to the presence of some deteriorating poles, so the Company would respond to that by replacing those poles. If the line had a score indicative of various other equipment issues, then a full line rebuild may be more appropriate.

However, the Company does not necessarily "go down the list" in prioritizing and scheduling HVD projects. Many large HVD projects have multi-year schedules, with a series of steps that must be completed in order, and this affects when projects can be executed. For example, the substation with the highest asset score today may require a full rebuild. Rebuilding that substation may require the Company to acquire new real estate first and procure long lead time materials before construction can take place, meaning construction may not be possible for a few years. In the meantime, the substation with the

fifth-highest asset score today may be fixable through a quicker project that can be done this year. In this situation, the Company would be completing a technically lower-ranked project before a higher ranked one, due to timing issues. Additionally, the multi-year nature of some projects means that a future project may move up or down in prioritization while it is in development as information about other asset health needs come to light. This is one reason why an asset health model is useful in the first place: the Company can optimize asset health to reflect shifting needs.

Furthermore, the Company often tries to coordinate projects to create efficiencies, so projects may be moderately reprioritized to take advantage of keeping a workforce in a specific area, or to coordinate with other kinds of infrastructure work being done by state and local governments.

Q. If the Company does not invest in the HVD system at the levels proposed in the instant case, what risks will this create for the Company's system?

A. As noted earlier in my direct testimony, a single outage at an HVD or LVD substation or on an HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI and of customers impacted. The Company has documented an increase in the number of anomalies found on the HVD system, and the Company's asset health modeling gives the Company detailed insight into which assets need investment most urgently. If the Company does not make the needed investments in the HVD system, more assets will simply be run to failure, and HVD SAIDI would degrade; again, note that in 2025 the Company had HVD assets that were within months of failures that would have increased SAIDI by over 39.8 minutes. Throughout my direct testimony in the respective sub-program sections, and in my exhibits, I will explain how specific investments will deliver clear reliability benefits

to customers, particularly through future customer outage minutes avoided through the investments. In the aggregate, planned investments will not only *prevent* future large-scale interruptions to customers, but they will also *reduce* SAIDI on a net basis; this is the true value of investments in HVD reliability.

Q. How does the Company substantiate the idea that a single HVD outage is similar in impact to 50 LVD outages?

A. In 2024, the average LVD outage on the Company's system impacted 38 customers and contributed 0.003 minutes of SAIDI, while HVD lines and substation outages on the Company's system, on average, impacted 1,863 customers and contributed 0.18 minutes of SAIDI. This data highlights the impact that each HVD line and substation outage has on the system; while they have fewer total outage events, the outages that do occur are much more impactful than outages on the LVD distribution system.

Q. What role does the Company's inspections play in this process of identifying HVD investment needs?

A. As stated above, inspections provide critical inputs into the asset health model, helping the Company identify HVD investment needs in the medium to long term. Inspections are also crucial for identifying already failed components (which are then fixed in the HVD Lines and Substations Demand Failures sub-program) and in identifying components that present a near-term risk of failure (which are typically then addressed in the HVD Lines Reliability or HVD Substations Reliability sub-programs). In these situations, the Company develops a project to address the problem immediately or in the very short term; this kind of work does not go through the asset health model because there is no need to assess longer term risk when the asset has already failed or is about to fail.

Q. Does the Company make any investments in the HVD system that are not directly related to asset health or reliability?

A. Several HVD investment sub-programs address other important concerns. The HVD system plays a critical role in supplying electricity to large C&I customers that play an essential role in Michigan's economy. As Michigan attracts new large C&I customers, their demand for electricity will require expansion of the HVD system in certain areas, an issue that was discussed in the Reliability Roadmap. These needs are most specifically addressed in the Company's HVD Strategic Customers New Business and Metro New Business sub-programs, discussed later in my testimony. Issues related to load growth are also addressed in the HVD Lines and Substations Capacity sub-program and the LVD Substations Capacity sub-program, and the HVD Lines and Substations Capacity sub-program also addresses other important needs related to the functioning of the grid, such as interconnections with the transmission system.

Finally, the Demand Failures and Asset Relocations sub-programs addressed later in my direct testimony deal with emergent issues on the system that may not always be related to asset health.

III. LVD SUBSTATIONS STRATEGY

Q. Please provide an overview of the Company's LVD substations.

A. The Company has 832 LVD substations in its system to step down voltage from the HVD lines system to the LVD lines system. LVD substations are supported by the Company's fleet of mobile substations, which provide continuity of electric service to customers during planned and unplanned LVD substation outages where redundancy is not present or load transfers to adjacent substations are not available.

Q. What challenges are faced by the Company's LVD substations?

A. As with the HVD substations, the Company's LVD substations face similar asset health risks that the Company must address in order to maintain continued reliability for customers, especially because LVD substations do not always have the same levels of redundancy as HVD substations. As with the HVD substations, LVD substations have their own asset health models to inform investments, which I will address in more detail in the section of my direct testimony covering the LVD Substations Reliability sub-program. LVD substations face some unique challenges that are addressed through corresponding investment categories that I will discuss in my direct testimony, such as animal intrusions and the use of obsolete Allis Chalmers transformers, which both drive investments in LVD substations.

Additionally, the locations of LVD substations on the system – often in communities relatively close to load – means that LVD substations are particularly susceptible to the impacts of localized load growth, which drives the need for investments in LVD Substations Capacity.

IV. METRO SYSTEM STRATEGY

Q. Please provide an overview of the Metro system.

A. The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s through the 1950s to accommodate electric distribution in already busy downtown areas. Metro infrastructure is used, both in the past and today, to manage the electrical energy density of downtown city centers, facilitate electrical repairs, and for aesthetics.

The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited right-of-way ("ROW") in public streets and alleys. The Company's LVD Metro Planning & Design group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas of economic growth and vitality.

Q. What challenges are faced by the Metro system?

A. As with the HVD system and LVD substations, the Metro system also faces asset health risks that the Company must address to ensure continued electric reliability for customers in those six downtown areas. The Metro system has its own asset health model, which I will discuss in more detail when addressing the Metro Reliability sub-program later in my direct testimony. In addition to the six downtown cores, the LVD Metro Planning & Design team also manages high-rise services in various locations throughout the state. A high-rise service is an apartment complex, typically with senior and/or low-income housing, with vaults on various floors in the complex. These vaults are similar in design and function to those located in the Metro systems of downtown cores. Historical design standards required these vaults in buildings with four or more stories to ensure sufficient customer voltage. The Company began systematically inspecting these vaults in late 2025 and is beginning to review whether programmatic repairs and modernization are required, but the Company is not proposing any new spending for this work in the instant case.

The Company is also undertaking a Metro Modernization effort in order to integrate the Metro system into Advanced Distribution Management System ("ADMS"). Metro Modernization will introduce specialized sensors to detect water or gas hazards in the Metro

system and install switching equipment to allow for remote-control capabilities in Metro operations. Metro Modernization is being managed by the Company's Grid Automation team, and is discussed in detail in the testimony of Company witness McPhail.

New economic development and large infrastructure projects continue to emerge in some of the downtown areas, necessitating increased investment in the Metro New Business and Metro Asset Relocations sub-programs, which I will discuss later in my direct testimony.

V. CAPITAL SPENDING PROGRAMS

Q. How does the Company classify its HVD capital investments?

A. As explained by Company witness Duke, the Company makes capital investments under two broad classifications, *planned* and *unplanned*. Each of these classifications include capital programs addressed in my direct testimony, as outlined in Figure 9 below. Each classification corresponds to one or more capital programs, which are in turn divided into constituent sub-programs and investment categories.

FIGURE 9
PROGRAM CLASSIFICATION DESCRIPTIONS & HVD SUB-PROGRAMS

Classification	Description	HVD Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades and investments in new tools and technology	Reliability, Capacity, "Electric Other"
Unplanned	Demand-driven and customer-driven needs	New Business, Demand Failures, Asset Relocation

Q. Please summarize the HVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend $434,899,000 in capital projects on the HVD system, substations, and the Metro system in the test year, and $464,890,000 in the

bridge period. This investment plan is summarized by capital program in Figure 10 below. Increases in the various program areas are covered in their respective sections later in my testimony detailing the need to increase funding and how customers benefit from the projected level of spending.

FIGURE 10
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURES BY PROGRAM ($000S)

Work Type	HVD Program Area	2025 Actuals	Bridge Period	Test Year
Planned	Reliability	$ 226,834	$ 298,905	$ 280,619
	Capacity	$ 53,618	$ 60,788	$ 57,355
	Electric Other	$ (8)	$ 179	$ 271
Unplanned	New Business	$ 47,030	$ 52,228	$ 55,801
	Demand Failures	$ 24,595	$ 25,390	$ 21,683
	Asset Relocation	$ 14,963	$ 27,400	$ 19,169
Total		**$ 367,032**	**$ 464,890**	**$ 434,899**

Q. What capital projects does the Company expect to invest in during the bridge period and test year?

A. A comprehensive list of currently identified Company HVD projects and associated expenditures for the bridge period is provided in Exhibit A-156 (KKL-3), and a list of currently identified projects and associated expenditures for the test year is provided in Exhibit A-157 (KKL-4). Detailed discussion on each capital program and sub-program is provided in the respective sections of my direct testimony.

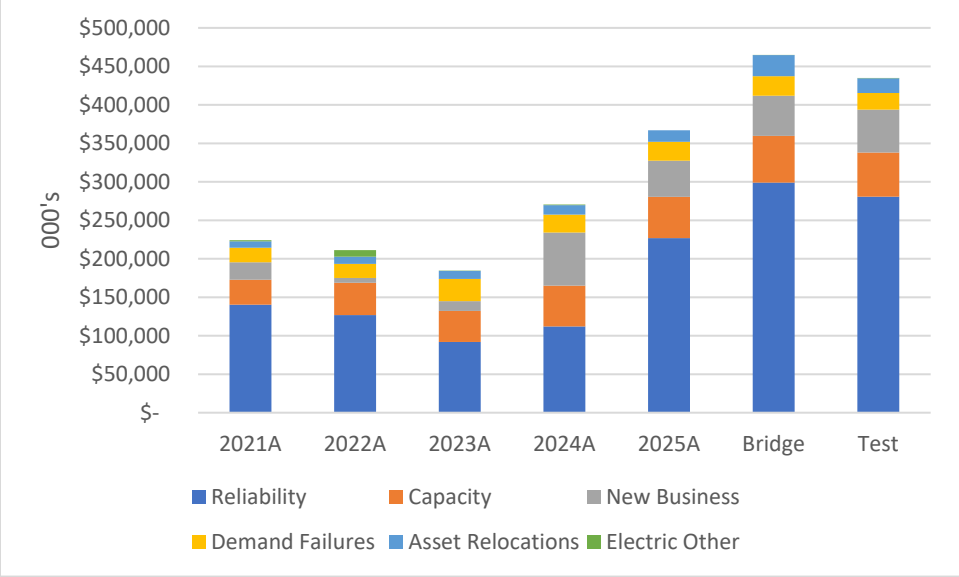
Q. Are contingency expenses included in any of the projected capital expenditures included in your testimony?

A. No. Contingencies are not included in the projected capital expenditures.

Q. How does the HVD capital expenditure plan in this filing compare to historical investments?

A. An overview of historical HVD capital expenditures by program from 2021 through 2025 and projected HVD expenditures for the bridge period and test year are shown in Figure 11 below.

FIGURE 11
HVD INVESTMENT BY PROGRAM



Q. Why are investment levels higher in the bridge period and test year compared to recent historical levels?

A. As discussed above, the Company has increased its investment levels to align with the levels established in the Reliability Roadmap to be able to deliver on its reliability goals. To ensure reliability and resiliency, the Company must focus on hardening and improving the performance of assets in poor health on the HVD system like poles, wire, breakers, relays, and transformers. This reliability spending allows the Company to address asset health risk proactively and keep assets within their intended useful lifecycle. The goal with reliability is simple: fewer and shorter outages for customers. Additionally, the Company has

increased investment relative to historical levels in the HVD Strategic Customers New Business sub-program in order to meet the needs of new and expanding C&I customers, and has increased investment in the Metro New Business and Metro Asset Relocations sub-programs to accommodate developments in several downtown areas, issues which are discussed in the Reliability Roadmap. Finally, it is important to note that the bridge period is 16 months long, so total spending is higher in absolute terms than in the other 12-month periods shown in the chart.

Q. Are there any general principles that govern how HVD assets are identified so the Company can develop targeted projects for those assets?

A. In general, projects are identified using data inputs in the asset health model, as discussed earlier in my direct testimony. Gathered data informs the Company on an asset's health based on likelihood, consequence, and severity of an asset's failure, also known as that asset's risk. Data is used to update asset health scores on a regular basis. When assets are identified as being at risk, the Company develops projects to address that risk proactively.

Q. When the Company identifies assets that are at risk and require investment, how does the Company identify and validate that HVD capital investments are reasonable and prudent for customers?

A. For many projects, the Company considers its proposed electric distribution investment against alternatives and develops a "concept approval" to test and demonstrate why the selected project is reasonable and prudent, as discussed in more detail in the direct testimony of Company witness Duke. As she discussed, Company projects are generally selected using the "least-cost, best-fit" principle. Through this vetting and concept approval process, the Company ensures that it has a strong and robust justification for electric distribution

projects that are selected for implementation. The general structure of a concept approval includes the following:

1. Identification of the system risk;
2. Identification of alternatives to address the system risk;
3. Determination of costs and benefits of the alternatives;
4. Selection of best alternative;
5. Approvals; and
6. Revisions, where necessary.

Q. What happens following the concept approval process?

A. Once projects have necessary internal approvals, the Company can begin to execute them. Many HVD projects are complex and play out over multiple years. It is important to note that capitalized activities often take place before construction begins. For example, the Company may be engaged in ROW procurement a year or more prior to construction, and it may have to make "progress payments" to secure future delivery of equipment (this is discussed in greater detail below). The Company is often engaged in detailed design work for one to two years before construction begins as well. All of these preconstruction capital activities can contribute to the way that a project can take place over multiple years, with spending across multiple years before a "unit" is field complete (this is also discussed in greater detail below).

Q. How do customers benefit from the concept approval process?

A. The concept approval process provides a rigorous approach and governance structure to identifying HVD system problems and needs, alternative solutions, and recommended

alternatives. It provides for peer review and management oversight to ensure that the Company's investment plans are well justified, reasonable, and prudent for customers.

Q. How are these projects justified as reasonable and prudent investments for the customer?

A. As mentioned above, an asset's health is identified through the Company's various health models which leads to the development of a concept to address any asset health concern. This process ensures that the Company continues to prioritize work based on the assets that are in poor health and represent the greatest risk to system performance. Conversely, assets near failure as identified during regular inspection of the HVD system that need to be addressed in a timely manner to prevent customers from experiencing an outage do not follow the concept approval process because there are only two options: replace the asset prior to failure or replace it after it fails which causes an outage to customers. As discussed in the HVD system overview, running assets to failure without doing proactive work would result in a significant increase in customer outages and HVD system SAIDI. The increase in proactive spending allows the Company to address system health and degradation before customers experience outages. These system defects are prioritized according to their risk to system operations and customer reliability and executed to the greatest efficiency to prevent an actual failure.

Q. Can you further discuss the implications of projects taking place over multiple years?

A. As discussed above, many individual projects take place over multiple years, incurring capital expenditures over multiple years, before the project is field complete. This is important to keep in mind when attempting to analyze purported unit costs in some sub-programs and investment categories. In recent electric rate cases, some intervenors have

analyzed the Company's projected spending by calculating a unit cost, typically by dividing the projected spending for a given period by the number of projected units for that same period. Although this can sometimes be a reasonable approach, it is not the best approach for evaluating multi-year projects. In a multi-year project, the Company can make capital expenditures in a given year, but if the project is not field complete in that year then there is no corresponding unit to divide by. Exhibit A-156 (KKL-3) and Exhibit A-157 (KKL-4) list all of the Company's planned bridge period and test year projects. When a project is planned to last beyond the period covered by the respective exhibit, the "units" column for that project will typically indicate "0."

Q. Do projects in HVD investment sub-programs typically have consistent, linear spending throughout the year?

A. Not necessarily. Some projects are weather dependent, and may not be possible at certain times of year, such as when frost presents an issue. Some projects are also dependent on when the system can be reconfigured to keep serving customers while a given piece of equipment is taken out of service. Because of these types of issues, it is possible for the majority of work in some sub-programs to be confined to certain seasons; for example, if summer load constraints prevent system reconfiguration during the summer, then related work could largely take place in the fall, and this would mean that the work could inaccurately appear behind schedule if a simple snapshot of year-to-date work were taken in the summer.

Q. What is the nature of "progress payments," and how do they work?

A. Progress payments are capital expenditures made ahead of delivery in order to ensure that the Company will receive transformers and other key long lead time equipment (such as

high-voltage circuit breakers) when they are needed for project construction. In the current environment, this equipment cannot be procured on an as-needed basis; it must be ordered ahead of time, sometimes years in advance, and progress payments are a necessary part of this process. Progress payments are tied to specific milestones in the manufacturing process and are managed to ensure that equipment ordered by the Company is available when needed. As noted above, progress payments contribute to the types of capital expenditures for a given project being spread over multiple years in many cases. Progress payments impact a number of capital sub-programs in my direct testimony, and I will discuss sub-program specifics in the respective testimony sections.

Q. Why are progress payments necessary?

A. In recent years, the North American electric industry has faced persistent supply chain constraints for equipment like large transformers and high-voltage circuit breakers. Manufacturer lead times that averaged 12-18 months prior to 2020 have expanded to an average of 24-36 months or more, driven by global shortages of steel and other raw materials; increased domestic demand due to grid modernization and electrification; manufacturing production backlogs; and policy initiatives accelerating interconnection and infrastructure projects. These phenomena create difficulty with timely procurement of this equipment, resulting in construction deferrals, cost escalations, and negative reliability impacts. These challenges indicate that it is insufficient to simply order equipment in advance; progress payments are needed to ensure equipment vendors make progress building equipment for specific projects.

Consequently, the Company began making progress payments to manufacturers for critical equipment in the second half of 2025 to ensure delivery when construction is

scheduled for the relevant projects. In addition to guaranteeing timely delivery of equipment to the Company, progress payments reduce future cost uncertainty that could result if equipment was not available when needed; late-stage rescheduling and/or emergency sourcing of equipment adds to costs ultimately borne by customers.

VI. HVD SUB-PROGRAM SPENDING DETAILS

A. Planned Spending Programs

1. Reliability

Q. Please describe the Reliability sub-programs.

A. The overall purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, as described by Company witness Duke. In my testimony, I will address eight HVD Reliability sub-programs:

- HVD Lines Reliability
- HVD Substations Reliability
- Transformer Bank Replacements and Substation Rebuilds
- LVD Substations Reliability
- LVD Substations Rehabilitation
- Metro Reliability
- Metro Rehabilitation
- System Protection

a) HVD Lines Reliability

Q. Please explain what projects, activities, and other types of work are accomplished by expenditures in the HVD Lines Reliability sub-program.

A. HVD Lines Reliability investments are intended to address deteriorated HVD line assets that have been assessed to be in poor health, mitigating and reducing the contribution of the Company's HVD lines to SAIDI and improving their resiliency. Work in the HVD Lines Reliability sub-program consists of seven investment categories:

- HVD line rebuilds
- Pole top rehabilitation miles
- Individual pole top replacements
- Pole replacements
- Switch replacement projects, including SCADA additions
- Line sensor deployments
- ROW Acquisition for HVD line rebuilds

Each project in this sub-program is customized to address the particular issues on individual poorly performing assets and deteriorated lines, based on an asset's, or collection of assets', risk to system performance.

Q. Has the Company made any recent changes to the investment categories in this sub-program?

A. Line sensors and ROW acquisition were new investment categories in this sub-program in Case No. U-21585 in 2024. Line sensors were historically in the HVD Lines and Substations Capacity sub-program but were transferred because their main function is to improve the reliability monitoring of the system and assist with quick identification of faulted line segments. ROW acquisition for reliability projects was also historically in the

HVD Lines and Substations Capacity sub-program, but was transferred in order to better align the costs of line rebuilds with the actual work.

Beginning in Case No. U-21870, the Company took investment that was formerly in a sub-program called HVD Lines and Substations Rehabilitation, which included various types of investments focusing on line and substation assets that were assessed to be at risk of imminent failure, and shifted work related to HVD lines that had been in that sub-program to HVD Lines Reliability, so that all investments addressing the reliability of HVD lines is now within one sub-program.

Other work that was formerly included in the HVD Lines and Substations Rehabilitation sub-program was transferred to the HVD Substations Reliability sub-program beginning in Case No. U-21870, as discussed later in my direct testimony. The remaining work that was formerly included in the HVD Lines and Substations Rehabilitation sub-program is now included in the Transformer Bank Replacements and Substation Rebuilds sub-program, as also discussed later in my direct testimony.

The scope of the HVD Lines Reliability sub-program has not changed since Case No. U-21870 was filed.

Q. How did this transfer of work from one sub-program to another affect the investment categories in the HVD Lines Reliability sub-program?

A. The changes made in Case No. U-21870 are illustrated in Figure 12 below.

FIGURE 12
CHANGES TO HVD LINES RELIABILITY INVESTMENT CATEGORIES IN CASE NO. U-21870

Investment Category	Change in Case No. U-21870
HVD Line Rebuilds	No Change
Pole Top Rehabilitation Miles	No Change
Individual Pole Top Rehabilitations	New to HVD Lines Reliability; formerly in HVD Lines and Substations Rehabilitation
Pole Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Switch Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Line Sensors	No Change
ROW Acquisition	No Change

Q. How does the HVD Lines Reliability sub-program deliver on the intent of the Reliability Roadmap?

A. As discussed in the Reliability Roadmap, the Company's primary strategy for HVD lines is to address HVD line components – poles, pole tops, conductors, and switches – with poor asset health through a workplan that replaces those assets that have been identified as having poor health. The Company focuses on lines with consistently poor reliability performance and looks for the best remediation strategy to reduce risk and prevent future outages in the most effective and economical way, generally using a least-cost, best-fit approach.

As described in the Reliability Roadmap, this sub-program specifically addresses risks in the four major components of the HVD lines system: conductors, insulators, poles, and switches. The Company identifies and assesses the health and risks related to these four major components and mitigates that risk using a combination of line rebuilds, pole top rehabilitation, and switch and pole replacements to reduce the population of each asset at risk and improve reliability performance. The HVD Lines Reliability sub-program is

aligned with the Reliability Roadmap because it executes the projects listed in Exhibit A-156 (KKL-3) and Exhibit A-157 (KKL-4) for specific HVD line rebuilds, pole top rehabilitation projects, switch replacements, and individual pole replacements needed to continue to address the asset health risks on conductors, insulators, poles, and switches identified in the Reliability Roadmap.

While the Reliability Roadmap primarily connects these HVD lines investments to reducing asset health risk, these investments also play a key role in SAIDI performance, as discussed by Company witness Duke.

HVD Line Rebuilds and Pole Top Rehabilitations Miles

Q. What kind of work is done in the HVD line rebuilds and pole top rehabilitation miles investment categories?

A. HVD line rebuilds consist of a complete rebuild of a line or line segment, including insulator, conductor, cross-arm, and pole replacements. Pole top rehabilitation miles consist of replacing deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops without replacing the poles themselves, again along an entire line or line segment. Lines in poor asset health that currently meet modern construction and design standards, and that have standard conductors, will primarily receive pole top rehabilitation, while lines in poor asset health that use non-standard and obsolete construction or equipment will typically be rebuilt.

HVD line rebuilds take conductor, poles, and insulators in poor asset health off the system as lines are rebuilt to current construction standards/configurations. Pole top rehabilitation projects directly address lines with poor insulator health which is the leading

cause of line outage events over the past five years. See Company witness Duke's testimony.

Q. How does the Company determine which HVD line sections should be addressed with line rebuild or rehabilitation projects in this sub-program, and how does it determine whether to rebuild the line or only do rehabilitation?

A. The Company utilizes past system performance and asset health data collected from inspection programs to identify and prioritize projects that will optimize system performance, reduce risk, and provide benefit to customers through improved reliability. This data builds a model to prioritize HVD line segments based on actual outage history, conductor type and configuration, health of insulators and poles, and the potential customer impact if the line segment were to fail.

With few exceptions, lines that use non-standard and obsolete construction or equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms, structure replacements, tree clearing, and ROW procurement as needed. Lines that use standard construction and conductor, have adequate pole health, but have poor insulator health, are candidates for pole top rehabilitation instead of a complete rebuild.

Q. Why does the Company rebuild lines that use non-standard and obsolete construction or equipment?

A. HVD lines with non-standard construction typically have higher outage rates due to their outdated construction standards, such as unshielded conductors (which are more vulnerable to lightning), small single-layer conductors, or copper conductors (both of which are less durable than standard construction and require non-standard components to repair them

when they fail). Pole top rehabilitation does not mitigate these issues. Rebuilding a line to modern standards improves durability and operational flexibility.

It is critical to remember that line rebuild projects and pole top rehabilitation projects both address lines that have already been identified as having outage problems. The question is simply whether the best way to address those problems is through a rebuild or rehabilitation.

Q. Please further explain the impact of asset health risk on project selection.

A. As shown in Figures 13 and 14 below, a substantial percentage of the Company's HVD lines insulators are at risk, with 34% falling into the vintage and victor, concerned and high-risk categories. Lines with high population of these insulators are considered to be in poor asset health and are prioritized accordingly. Similarly, conductor assets are also at some risk, with 14% of conductors classified as high risk based on their condition. Proposed line rebuild projects directly address the lowest 20% of at-risk conductors in line conductor health by bringing those lines into the green portion of the donut chart. A major purpose of the Company's projected increase in HVD Lines Reliability investments is to address these risks.

FIGURE 13
HVD LINE INSULATOR HEALTH

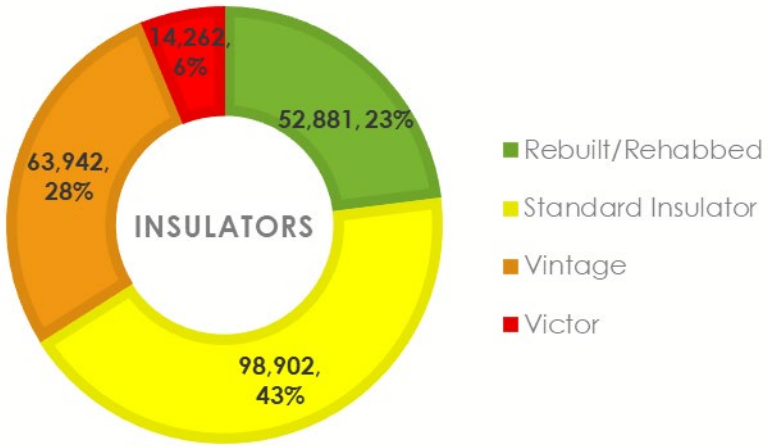
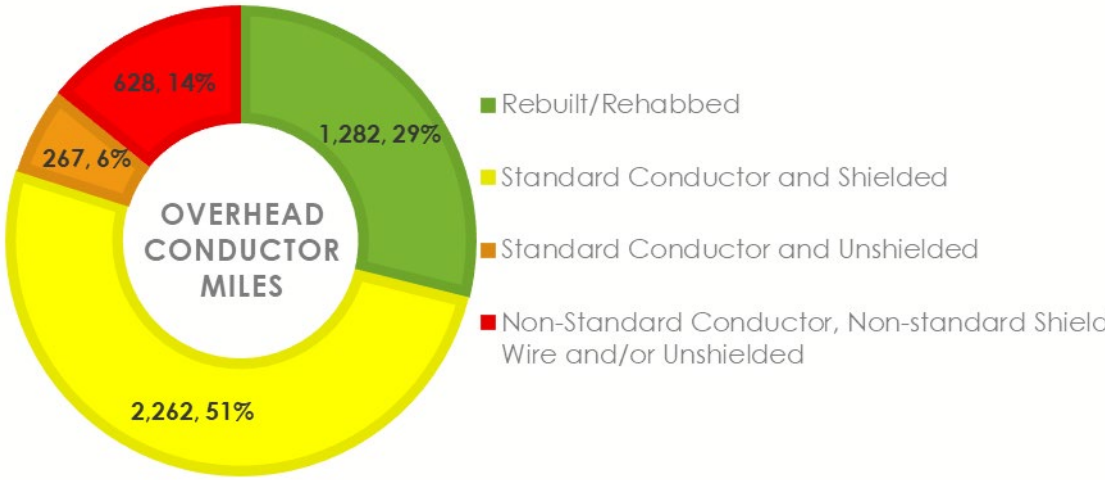


FIGURE 14
HVD LINE CONDUCTOR HEALTH

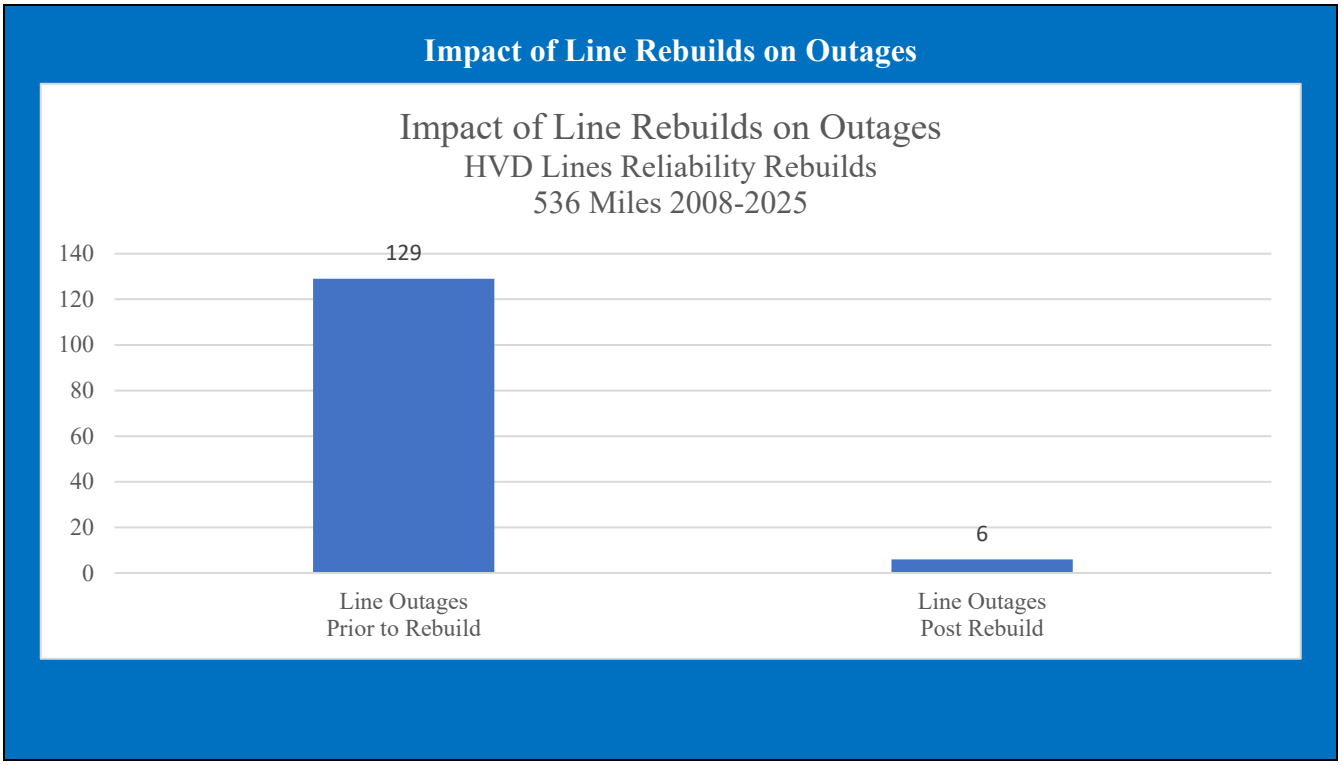


Q. What specific benefits have HVD line rebuilds delivered for customers?

A. Line rebuilds substantially improve the performance of a line, reducing or eliminating outages and correspondingly reducing or eliminating interruptions to customers caused by that line. Figure 15 below shows how, after completing a line rebuild, a line section typically experiences minimal line equipment-related outages with a demonstrated 96% reduction in outages.

In Figure 15, Prior Outages represent the number of line outages due to equipment failure within the line section specified in the order number that occurred during the five years before the rebuild Completion Date. Post Outages represent the number of line outages due to equipment failure that have occurred since the Completion Date within the rebuilt line section. Customers realize the benefit of fewer outages when the Company rebuilds an HVD line section.

FIGURE 15



Individual Pole Top Replacements

Q. What work is done in the individual pole top replacements investment category?

A. The individual pole top replacements investment category does similar work to the pole top rehabilitation miles investment category, but instead of addressing entire lines or line segments, the individual pole top replacements investment category only replaces individual pole tops that represent an imminent failure risk. As noted above, individual pole top

replacements were formerly accounted for in the HVD Lines and Substations Rehabilitation sub-program.

Q. Why does the Company perform both pole top rehabilitation projects and individual pole top replacements?

A. Although both investment categories involve replacing pole top infrastructure, projects are identified in two different ways. With the pole top rehabilitation miles investment category, the Company determines that the pole tops on an entire section of line are in poor asset health and should be replaced in a single project, taking advantage of the efficiencies that exist when crews can work on a single line for a period of time. Individual pole top replacements are done when inspections identify single pole tops at risk of imminent failure, but where it would not be justified to replace pole tops on an entire section of line. While pole top rehabilitation miles are larger projects that are planned months or years in advance, individual pole top replacements are generally executed more quickly after identifying the deteriorated pole top.

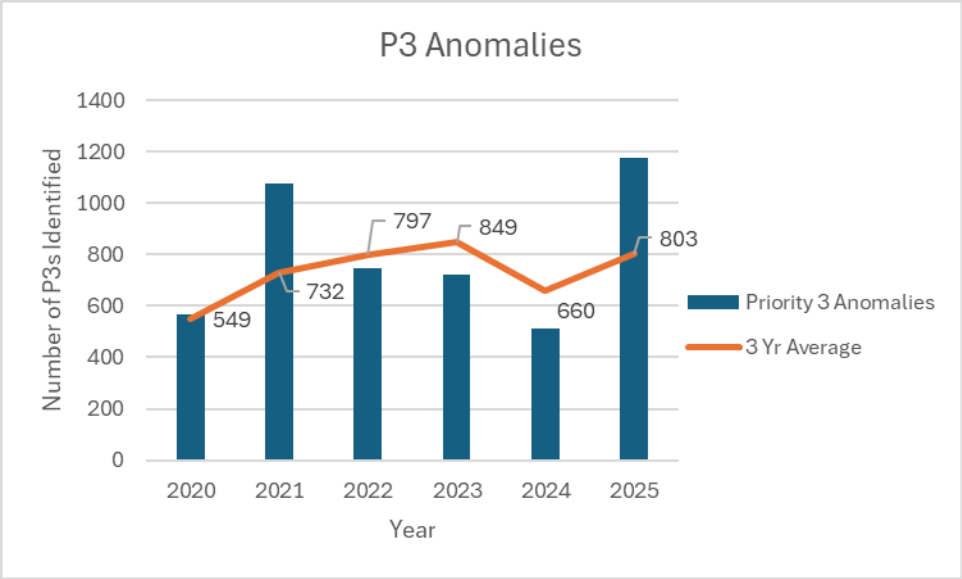
Q. How does the Company identify individual pole tops that are at imminent risk of failure?

A. Individual pole top replacements are identified almost exclusively by helicopter and ground inspections. Pole top replacements identified as Priority 1 and some Priority 2 anomalies are replaced under the HVD Lines and Substations Demand Failures sub-program. The remaining Priority 3 anomalies represent imminent failure risk and fall into this sub-program.

During these inspections, the Company identifies anomalies visually using a camera that combines corona camera technology (for detecting cracked insulators using ultraviolet

technology) with an infrared camera (to detect elevated thermal activity) during helicopter inspections to detect anomalies with high levels of accuracy. As shown in Figure 16 below, the Company is consistently identifying over 600 anomalies per year, with an average of over 800 anomalies per year. This indicates that consistent investment in this category is needed to keep up with the on-going deterioration of pole top assets such as cross arms and insulators. Failure to do so will result in worsening asset health risk on HVD lines, increased failures, and increased spending in the HVD Lines and Substations Demand Failures sub-program.

FIGURE 16



Q. Can you provide further discussion on the Company's helicopter and ground inspections?

A. The Company performs aerial inspections of its HVD lines system via helicopter. As this is a highly effective way to reduce HVD lines-related customer outages, the Company has adjusted its helicopter inspection program to ensure flights happen earlier in the year and more often to support the identification and correction of anomalies before they result in outages.

The results of the helicopter inspection program are a significant source of information to determine immediate action items. For example, a flight conducted with an ultraviolet corona camera identified an insulator on one of the Company's 46 kV lines that was emitting a corona signature (see Figure 17 below), prompting an immediate replacement of the insulator to avoid an outage on the line, which would have interrupted 2,000 customers. The insulator in question was found to be cracked (which can result in emission of corona) and was in imminent failure status. In this figure, the image on the top left shows what the corona camera sees, with the red areas indicating that corona emissions are detected. The image on the top right shows the same insulators upon closer visual inspection, with the circle and arrow indicating where the insulator is cracked. The image on the bottom shows a closer view of the same insulator.

FIGURE 17
UV ANOMALY IDENTIFIED WITH CORONA CAMERA



For safety reasons, helicopters do not fly over approximately 400 specific miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency within the areas of these miles. Most of these "no-fly lines" are in urban areas. To inspect these lines, the Company performs a combination of driving, walking, or use of drones to complete patrols of all 400 of these miles over the period of two years with a target of 200 miles inspected per year. These inspections may include infrared and/or corona inspection using handheld cameras.

Q. Can you provide visual examples of assets identified through these inspections?

A. Figure 18 below is representative of common Priority 3 findings identified by helicopter inspection. These assets are in advanced stages of deterioration and at increased likelihood of failure. The arrows pointing to the cross arms indicate where they are cracked, splitting, and starting to fail as the arm is no longer straight. Figure 18 shows how quickly these assets can deteriorate once these reach a Priority 3 status. In Figure 19, the same structure is photographed three months apart with the left side of the image being the first photo taken and the right side of the image being the same structure three months later. These photos indicate noticeable deterioration in the cross arm, as light is showing through the image on the right but not in the original. When anomalies like the ones shown below are not addressed through this sub-program, failures follow, causing interruptions to a large number of customers and increasing spending in Demand Failures, where reactive work is more expensive.

FIGURE 18
PRIORITY 3 CROSS ARM DETERIORATION EXAMPLES



FIGURE 19
PRIORITY 3 CROSS ARM 3-MONTH DETERIORATION



In Figure 19, the left side is original, and the right side is three months later.

Pole Replacements

Q. What work is done in the pole replacements investment category?

A. Targeted pole replacements address poles identified during a previous annual pole inspection cycle that need to be replaced prior to the next inspection cycle.

Q. What is the Company's HVD pole inspection methodology and pole replacement criteria?

A. The Company's inspection and replacement criteria are provided in Exhibit A-154 (KKL-1) and are the same criteria the Company presented in other recent electric rate cases. The Company inspects HVD poles on an approximately 12-year cycle. A contractor performs visual inspections, sonic inspections, and bore testing on all poles 11 years old or older along specified line sections.

Q. How is this methodology used to identify poles in need of replacement as part of the pole replacement investment category in this sub-program?

A. HVD pole replacements in this sub-program are identified through the pole inspection program. Identified poles are grouped by line segment and reviewed to be included in a line rebuild project, line rehabilitation project, or individual pole replacement based on other line characteristics. For annual pole inspections, the Company identifies in advance which HVD lines will be inspected, so the Company knows which HVD lines will require pole replacements in the future based on inspection results. Given data about historical pole inspection failure rates, the Company can determine not only the HVD lines that will require replacements, but also how many poles on a given line are likely to require replacements. In 2026, the Company is planning to inspect 7,517 HVD poles across 105 different line sections as identified in Exhibit A-155 (KKL-2).

Q. Please further explain Exhibit A-155 (KKL-2).

A. In Exhibit A-155 (KKL-2):

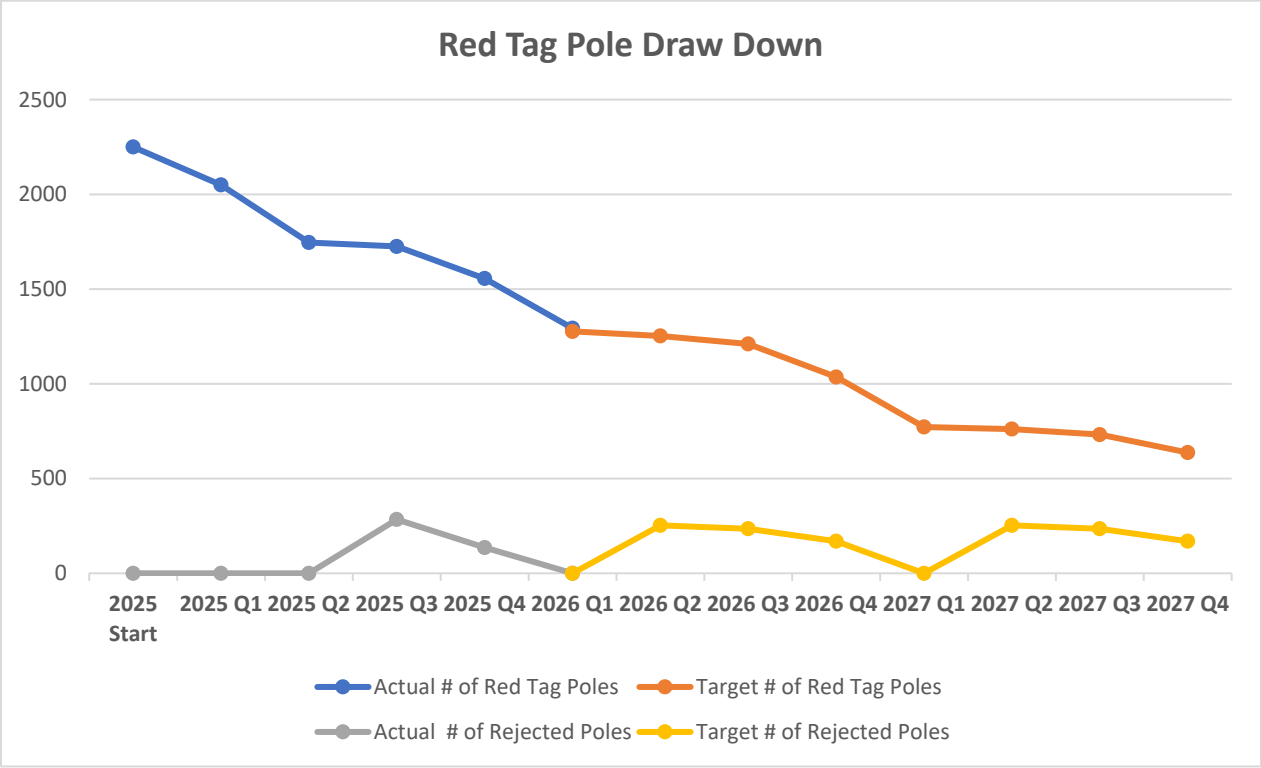
- Column (a) identifies HVD line names and column (b) identifies how many poles will be inspected on that line;
- Column (c) identifies how many poles on each line the Company expects to be rejected during inspection, based on historical rejection rates; and
- Column (d) identifies the cost associated for the replacement of rejected poles.

Poles identified during this inspection process, along with poles identified during previous inspections yet to be completed, will form the pole replacement plan for the test year.

Q. How many poles has the Company identified during previous inspection cycles and not yet replaced?

A. To start the first quarter of 2026, the Company had a backlog of approximately 1,560 red-tagged HVD poles that were identified in earlier inspection cycles but have not yet been replaced. Those poles also inform the replacement plan for the bridge period and test year and will supplement poles identified by ongoing inspections outlined in Exhibit A-155 (KKL-2). The Company plans to clear this backlog through 2027, as shown in Figure 20 below. The figure accounts for projected pole replacements in this sub-program for the bridge period and test year in addition to the projected number of poles expected to be rejected and added to the backlog from inspections. It is essential that the Company continue working to reduce this backlog, as any rejected pole that remains in the field represents a safety risk to the public and to employees.

FIGURE 20
PROJECTED RED-TAGGED POLE BACKLOG



Q. Do pole inspections help identify projects for any other investment categories in this sub-program?

A. Yes. Switches are identified for replacement when the supporting pole is identified for replacement during the pole inspection program. As switch availability is critical for system operations, these locations are prioritized for replacement. Therefore, specific switch replacements in the test year will also be identified during 2025 pole inspections.

Q. Are there other reasons to replace HVD switches?

A. Yes. HVD switches, including Motor Operated Air Break Switches ("MOABS"), are critical pieces of equipment that aid in the efficient isolation of faults, which can shorten or mitigate outages for customers when a fault occurs. When these switches are inoperable, it often results in more customers experiencing an outage and/or customers remaining without service longer than if the switch had been available for operation. These switches are identified for replacement through field operations feedback on operability concerns and inspections. For example, MOABS are inspected regularly as their controls require power to operate, and since they are called on to operate when the lines they are attached to lose power, batteries provide power to the control of the MOABS to allow them to operate appropriately. Periodic battery replacement ensures that power is always available to operate the device. MOABS are tested annually to ensure the controls are in proper working order and the batteries are replaced every three to four years, or sooner as needed.

In Case No. U-21585 and prior cases, the Company performed switch replacements in both the HVD Lines Reliability and former HVD Lines and Substations Rehabilitation sub-programs. Beginning in Case No. U-21870, the Company is now combining all switch replacement work in HVD Lines Reliability.

Q. How can HVD switches improve reliability?

A. Based on the current population of HVD switches, ¾ currently require a field employee to physically visit the site and perform a switching operation. Switches installed in this sub program have the ability to be remotely operated from a control room which reduces the amount of time it takes to isolate faults on the HVD system. This has shown the ability to reduce switching time from over an hour down to 20 minutes (an approximately 67% reduction in SAIDI) when clear fault data is available. This technology is partnered with line sensors to give the control room clear visibility into which line segment a fault occurred in so that remote switching can be performed to reduce the length of outages to customers.

Line Sensors

Q. What kind of work is done in the Line Sensors investment category?

A. The Company installs line sensors on HVD lines to provide increased visibility into abnormal activity on the HVD system. Line sensors detect small variations in voltage and current patterns, when and approximately where abnormal conditions are happening, allowing the Company to investigate and take action before a possible failure occurs. In addition, when a fault does occur, line sensors can help pinpoint the location of the failure leading to quicker response, isolation, and restoration of service. Collected data aids in project identification for other investment categories within the HVD Lines Reliability sub-program. The Company continues to install line sensors with our switches to improve isolation times reducing SAIDI and Customer Average Interruption Duration Index ("CAIDI").

Q. Does the Company have line sensors installed anywhere else on the system? If so, what benefit has been realized after installation?

A. Yes, the Company has approximately 11,000 line sensors installed on the LVD system and 1,000 installed on the HVD system. As mentioned above, line sensors are being used to help identify abnormal line conditions that alert the Company to a possible issue. As a result, the Company has been able to investigate and correct these issues prior to them becoming faults and interrupting service to customers. When faults do occur where line sensor data is available, the data is being used to help locate the specific area of line that experienced the fault and remotely isolate the fault or route field personnel to those spots for quicker response, isolation, and restoration of service.

ROW Acquisition

Q. What is the purpose of ROW acquisition in this sub-program?

A. The Company may need to acquire new rights of way, or expand existing ones, for a number of reasons. New rights are often needed for relocation of existing lines during rebuild projects. Expansion of existing rights is often required when the Company is rebuilding a line in the existing corridor but cannot take the line out of service, and therefore needs a wider ROW so the Company can continue providing service while building a new line adjacent to the existing one. Additional rights may also be required when rebuilding a line to include larger conductor, requiring larger structures and larger structure supports. Finally, additional rights may be required to bring existing easements to current standards, allowing access for modern construction equipment and tree clearing standards. It can take up to 18 months to secure necessary rights from the time that ROW procurement begins, so continued proactive funding of ROW acquisition is necessary to support future work.

Q. How do you calculate the amount of ROW dollars needed for this sub-program?

A. The Company projects that it will cost $200,000 per mile for updating and expanding existing land rights needed to support HVD line rebuilds and pole top rehabilitation projects, based on the most recent actual ROW costs for an executed project. The Company is projecting to spend $7,331,000 in the bridge and $8,332,000 in the test period to support the acquisition of 37 miles and 42 miles of additional land rights, respectively.

HVD Lines Reliability: Overall Investment and Benefits

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Lines Reliability sub-program?

A. The Company is projecting HVD Lines Reliability capital expenditures of $135,685,000 in the bridge period and $108,778,000 in the test year. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 21 below.

FIGURE 21
HVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Benefit (customer minutes)	Test Year Capital	Test Year # of Units	Benefit (customer minutes)
Line rebuilds (miles)	$59,951,000	80.6	1,955,806	$41,365,000	33.2	877,178
Pole top rehabilitations (miles)	$9,753,000	141.4	3,778,916	$13,303,000	142.6	3,839,582
Pole replacements	$40,966,000	1,655	2,117,883	$25,753,000	1,040	1,343,672
Switches (incl. SCADA additions)	$8,468,000	65	66,544	$12,661,000	97	92,138
Pole Top Assembly Replacements	$6,842,000	800	1,023,750	$4,990,000	583	746,058
Line Sensors	$2,374,000	208		$2,374,000	208	
Right of Way Acquisition	$7,331,000	N/A		$8,332,000		
Total	**$135,685,000**		**8,942,899**	**$108,778,000**		**6,898,627**

Q. How many pole tops will be replaced as part of the pole top rehabilitation miles in the bridge period and test year?

A. The Company estimates that there are approximately 16 poles per mile in HVD lines that undergo pole top rehabilitation. Therefore, in the bridge period and test year, the Company estimates that 2,262 and 2,281 pole top assemblies will be replaced, respectively.

Q. What are the customer minute benefits shown in that table above?

A. As explained earlier in my direct testimony, customer outage minutes is a mathematical product of the number of customers that would experience an extended outage of electrical

service, and the duration in minutes of that outage, if a proposed project is not completed and the asset fails. A reliability project will lead to avoided future customer outage minutes by either reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. Calculations are based on assumptions for the number of impacted customers, outage duration, failure rate, and the number of units impacted. Assumptions are based on historical actual failures versus asset population, average number of customers impacted by lines events, and traditional response duration. Figure 22 below provides these assumptions used in bridge and test period calculations for the HVD Lines Reliability sub-program.

FIGURE 22
HVD LINES RELIABILITY CUSTOMER OUTAGE MINUTES ASSUMPTIONS

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Pole Replacements	3900	250	0.021
Switch Replacements	3900	250	0.021
Individual Pole Top Assembly ("PTA")	3900	250	0.04
HVD Other Projects	3900	250	0.021
HVD Line Rehabilitation per mile	Note 1	Note 2	0.02
Line Rebuilds Unshielded	Note 1	Note 2	0.032
Line Rebuilds Obsolete Conductor/ Shielded	Note 1	Note 2	0.022
Line Rebuilds Standard Conductor/Shielded	Note 1	Note 2	0.02

Note 1: Based on the customers fed from that specific line.
Note 2: Target restoration time based on system configuration. 125 Minutes for a looped line, 250 minutes for a radial line segment off a looped line, and 310 minutes for a complete radial line segment.

Q. What is the basis of the Company's requested spending level for the bridge period and test year in this sub-program?

A. The requested spending levels are based on the total of all costs in the Company's workplan. The costs for individual projects are developed based on information from actual project expenditures over the past five years that have been refined to take into consideration the project location, expected site conditions, project specific material needs, and any known anomalies in costs. The projected spending amounts for the bridge period and test year are determined by the combined costs of individual, planned projects and will allow the Company to complete the projects listed, and deliver the benefits defined, in Figure 11 above. The capital projects planned for the bridge period and the test year, as well as their investment categories, locations, and benefits to reliability, are shown in Exhibits A-156 (KKL-3), pages 1 and 2; and A-157 (KKL-4), page 1. Pole replacements will be identified based on the process discussed above and reflected in Exhibit A-155 (KKL-2), with further replacements in the test year also identified based on inspections done during 2026 and 2027. It is important to note that projects can span multiple years, so the dollar amounts reflected in the exhibits are only the amounts that will be spent in the indicated time periods and customer minute benefit is realized during the year of project completion.

Q. Are there projects in this sub-program that span multiple years?

A. Yes. Some HVD Lines Reliability projects, particularly line rebuild projects and pole top rehabilitation projects, can span multiple years as these projects typically take multiple months to complete, with the primary construction timeframe for these types of projects running from October through May. This construction timeframe is due to the peak loads seen during the summer months, which means sections of the HVD system cannot be taken

out of service for replacement during those months. This timeframe also complicates the tallying of units completed on a calendar year basis, as these larger projects are not partially counted in a calendar year where a portion of the work was completed. The units for these projects are only counted in the year the project is completed in the field and enters service.

Q. Overall, what benefits will customers realize through the Company completing work in the HVD Lines Reliability sub-program?

A. As discussed in the executive summary of my direct testimony, customers realize improved reliability and resiliency through the Company completing this work. Specific benefits of the bridge period and test year planned projects are identified in terms of customer outage minutes avoided. The customer outage minutes avoided for the bridge period and test year HVD Lines Reliability projects are quantified in Exhibits A-156 (KKL-3), pages 1 and 2, and A-157 (KKL-4), page 1.

These investments also improve the asset health of critical HVD components that would result in thousands of customer interruptions at a time when they fail. By improving the HVD system, customers will experience fewer outages and have faster restoration when outages do occur. HVD Lines Reliability investment is a component of the plan to achieve the Company's reliability outcomes as outlined in the Reliability Roadmap, as well as the overall SAIDI improvements discussed by Company witness Duke. Specific contributions of the HVD Lines Reliability sub-program to SAIDI improvements are presented in the direct testimony of Company witness Duke.

While investment in HVD Lines continues to support a downward trend in overall SAIDI impact, sustaining the increased investment in this sub-program that began in 2025 will also provide a significant value in proactive mitigation of deterioration and asset health

risk, as discussed above and in the Reliability Roadmap, and quickly fixing anomalies identified through inspections will prevent significant interruptions to customers before they occur.

Q. Does the Company consider any alternative approaches to the HVD Lines Reliability projects?

A. Yes, for each potential project the Company considers three options: line rebuild, pole top rehabilitation, or addressing multiple individual system component degradation. As described above, there are multiple factors that guide what approach is selected for each given project.

Q. What is the risk if the Company does not perform this work?

A. An additional approach would be to not complete this work, which would result in the degradation of assets, decreases in reliability, and an increase in threats to safety for customers and Company workers. This would also impact system resiliency by affecting how quickly customers can be restored. Customers would see an increase in outages as system degradation would outpace system corrections. This is not prudent, as it would result in more outages in service and increased costs to the customer in the long run as equipment would have to be replaced on an unplanned basis.

Q. What has been the historical actual spending in the HVD Lines Reliability sub-program for the past five years?

A. The historical actual costs by investment category for HVD Lines Reliability are shown in Exhibit A-87 (EMD-3), line 17. The Company's historical actual spending in the HVD Lines Reliability sub-program for the past five years is also shown in Figure 23 below.

FIGURE 23
HVD LINES RELIABILITY HISTORIC EXPENDITURES

2021	2022	2023	2024	2025	5-Year Average
$58,092,000	$42,565,000	$21,703,000	$32,264,000	$99,314,000	$50,788,000

Q. Please explain if the spending in any of the five historical years is a significant outlier.

A. Spending was reduced in 2023 to align with the Company's overall approved level of investment in the settlement approved by the Commission in Case No. U-21224. Since then, spending has increased to support the investment plan established by the Company in its 2023 Reliability Roadmap, with 2025 being the first calendar year to reflect the full increase outlined in that filing.

Q. How would these historical expenditures look if they included the work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program?

A. If one looked at the historical investments in HVD lines that were done in the former HVD Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 24 below.

FIGURE 24
HVD LINES RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2021	2022	2023	2024	2025	5-Year Average
HVD Lines Reliability Historical	$58,092,000	$42,565,000	$21,703,000	$32,264,000	$99,314,000	$50,788,000
HVD Lines Rehabilitation Historical	$10,204,000	$13,823,000	$8,793,000	$11,484,000	$0	$10,585,000
Total	$68,296,000	$56,388,000	$30,496,000	$43,748,000	$99,314,000	$59,648,000

Q. What are the historical unit costs for each of the HVD Lines Reliability investment categories?

A. The historical unit costs for each category are provided in Figure 25 below:

FIGURE 25
HVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2021	2022	2023	2024	2025	5-Year Average
Line rebuilds	$1,029,600/ mile	$455,500/ mile	$1,675,300/ mile	$741,800/ mile	$1,722,500/ mile	$899,700/ mile
Pole top rehabilitation miles	$123,500/ Mile	$75,700/ mile	$72,100/ mile	$113,700/ mile	$168,800/ mile	$119,600/ mile
Individual pole top replacements	$10,300/PTA	$9,900/PTA	$8,400/PTA	$10,200/ PTA	$15,400/ PTA	$10,600/PTA
Pole replacements	$24,200/Pole	$27,800/pole	$25,700/pole	$33,200/ pole	$43,300/ pole	$34,600/ pole

Q. Please explain any variation in unit costs over time.

A. Individual projects can vary widely in cost from project to project based on specific project conditions, and as a result, the year-end per-unit average cost can also vary. A prior study showed that the unit cost for a pole replacement can vary as much as 50% from the average. This variation is due to many factors including location, accessibility, the type of equipment needed to install, and the amount of matting necessary to avoid environmental damage. Furthermore, as discussed above, HVD Lines Reliability projects often extend from one year into the next, which affects the ability to calculate accurate annual unit costs by simply dividing a given year's investment by the given year's number of field complete miles or poles. For example, for individual pole replacements in Figure 25 above, the annualized unit cost of $43,300/pole reflects the majority of all costs associated with the work to install 1,431 poles; however, 207 of these poles did not reach field complete status in 2025. These all achieved field complete status early in 2026 instead. If these poles were

included in the unit cost in 2025 for pole replacements, then the 2025 unit cost would be $37,000/pole.

b) HVD Substations Reliability

Q. Please explain the HVD Substations Reliability sub-program.

A. The HVD Substations Reliability sub-program ensures the long-term safe and reliable operation of HVD substations, and ensures the ongoing asset health of HVD substations, with spending to make needed replacements of existing substation equipment. HVD Substations Reliability projects are identified and prioritized based on both asset health data and inspection results, as discussed below.

Q. Please provide a general overview of HVD substations and their purpose in the HVD system.

A. HVD substations take power from the 138 kV Transmission system and drop the voltage to feed the Company's 46 kV lines, that in turn feed the Company's LVD substations. HVD substations are designed with redundancy such that the failure of a single component in an HVD substation will typically not result in outages to customers. However, to facilitate repairs or construction, the HVD system is sometimes temporarily configured in a manner that may remove a layer of redundancy; additionally, if failures of multiple components in a substation occur in the same window of time, this could result in customer outages. While rare, these outages can have a significant SAIDI impact (two minutes of SAIDI or more, or greater than 1% of the Company's recent annual historical performance) when they do occur. In addition, there are many HVD substations that are now well beyond their intended design life, increasing the probability of major outages. Failure of one element in an HVD substation also increases the risk that a second failure will cause a cascading outage that can

expand to cover an entire region. To address these concerns, some HVD substations are being rebuilt under the Transformer Bank Replacements and Substation Rebuilds sub-program, which is discussed later in my direct testimony. Individual pieces or small groups of equipment that are of concern are addressed here, under the HVD Substations Reliability sub-program.

Q. What investment categories are included in the HVD Substations Reliability sub-program?

A. This sub-program consists of five investment categories:

a. Circuit breaker and circuit switcher replacements;

b. Transformer bushing replacements;

c. Switch replacements;

d. Other targeted replacement programs for specific equipment, such as voltage transformer replacements, substation lightning arresters, and animal mitigation; and

e. Replacements of equipment at risk of imminent failure.

The replacement rationale for each investment category is included in Figure 26 below.

FIGURE 26
HVD SUBSTATIONS RELIABILITY REPLACEMENT RATIONALE

Replacement Category	Rationale for Replacement	Impact to Reliability
Circuit Breaker and Circuit Switcher	Obsolete Parts	Failure can cause a much larger number of customer outages if it occurs during a line fault.
Transformer Bushings	Higher failure rates than average bushing	Failure can cause customer outages if bushings fail. Bushing failures can also cause entire transformers to fail at significant cost.
Switches	Obsolete switches (replaced in conjunction with other substation work)	Failure can affect ability to remove equipment from service. Can significantly affect outage duration and repair costs.
Other Targeted Replacement	Obsolete equipment, mobile pad additions, or animal mitigation improvements	Obsolete equipment or lack of mobile pads can affect restoration following an event. Fence and animal mitigation improvements prevent failures from external sources.
Replacements of Equipment at Risk of Imminent Failure	High failure rate and high-risk equipment, safety	This equipment has been identified as having the highest risk of failure based on historical failure rates or poor test results.

Q. Has the Company made any recent changes to the scope of work in the HVD Substations Reliability sub-program?

A. As noted earlier in my direct testimony, some work that was included in the former HVD Lines and Substations Rehabilitation sub-program in Case No. U-21585 and prior cases was transferred to the HVD Substations Reliability sub-program in Case No. U-21870. Specifically, the former HVD Lines and Substations Rehabilitation sub-program included projects to replace substation equipment at risk of imminent failure identified during inspections. That work was transferred to HVD Substations Reliability and inserted into the existing investment categories in this sub-program and is reflected in Figure 26 above; no new investment categories were defined. No further changes have been made since Case No. U-21870 was filed.

Q. Please explain substation inspections.

A. There are several inspection programs for substation equipment ranging from monthly patrol inspections, infrared inspections, to inspections of individual pieces of substation equipment. Similar to HVD lines inspections, these equipment inspections allow the Company to be proactive in identifying equipment near failure and generating short cycle planned work to replace an asset when that failure presents a risk to customer reliability and/or system operability and are critical for monitoring and addressing asset health concerns before the asset fails. Just as HVD lines inspections identify deteriorated crossarms and other components before they fail, substation inspections provide advance warning on a wide variety of substation assets in failing health.

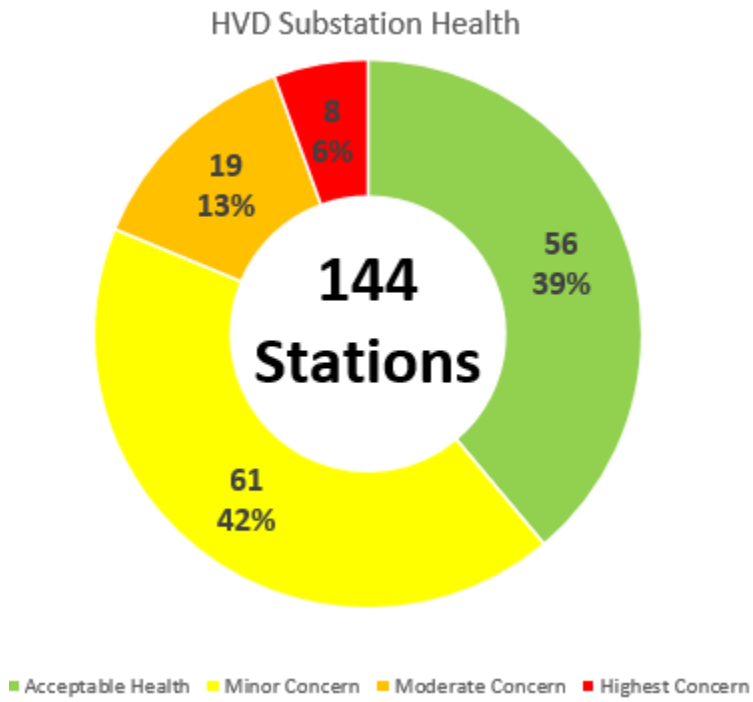
After identification, the work is planned, prioritized, and executed to mitigate the risk of unnecessary outages for customers or limitations to system operability. Lower priority issues that must be addressed but are not at imminent risk of impacting customer reliability or system operability, are planned for future years. When inspections identify anomalies indicating a high likelihood of failure that would cause an impact to customer reliability and/or system operability, the work is planned and executed to address the priority item in a short cycle fashion. Examples of equipment that would fall into this portion of this category include but are not limited to regulators, capacitor controllers, bushings, circuit breakers, lightning arresters, and switches.

Q. How does the HVD Substations Reliability sub-program deliver on the intent of the Reliability Roadmap?

A. As discussed in the Reliability Roadmap, the Company's primary strategy for HVD substations is to address substation components – particularly circuit breakers, transformer

bushings, and switches – with poor asset health through a workplan that replaces those assets that have been identified as having poor health, and/or assets that have been identified through inspections, as discussed above. 6% of HVD substations are a high priority for repair or replacement and an additional 13% show cause for moderate concern, as shown in Figure 27 below. Compared to the Company's assessment of HVD substation asset health at the end of 2024, this figure shows a reduction in the highest concern category from 15 to 8 and the moderate concern category from 30 to 19 , reflecting the effectiveness of projects completed in the past year.

FIGURE 27



While the overall percentages of substations in the high and moderate risk categories have decreased, there is still a significant risk in the remaining assets in the form of increasing levels of minor concerns, which will escalate to moderate and major concerns if not addressed. As discussed below, the Company is increasing its investments in certain investment categories in order to address specific risks in those categories, irrespective of

overall substation asset health scores. To address these risks, the Company outlined a plan in the Reliability Roadmap to increase investment in HVD substations.

Q. How does the Company identify specific pieces of equipment with poor asset health for replacement in the HVD Substations Reliability sub-program?

A. To identify substation equipment that may need replacement, the Company uses an asset health model that takes multiple inputs and analytic processes to aggregate numerous data sources to best target assets in poor health that are likely to cause reliability issues in the near term if they are not addressed. Based on the data in the asset health model, the timeline for correction can range from 1-2 months, to prevent a near term failure, up to a planned replacement coordinated with other work at the site in the following year. The inputs into the health model come from the multiple inspections within the Company's substation programs like infrared inspections, routine substation patrols, and diagnostic testing of transformers and breaker oil and gases. The overall philosophy and methodology behind the asset health model was discussed earlier in my direct testimony. Figure 28 below shows an example of an infrared anomaly of an insulator identified during inspection, which the Company would proactively address prior to a failure that would impact customers.

FIGURE 28



The model used to monitor the asset health of HVD substation assets is leveraged to identify specific areas to target investments based on likelihood, consequence, and severity of an asset's failure also known as that asset's risk. Projects are prioritized to deliver the greatest reliability improvements for the customer.

Q. What benefits will customers realize through completing the HVD Substations Reliability sub-program work, as proposed in this case?

A. The primary benefit of investing in HVD Substations Reliability at the levels proposed in the instant case is the significant improvement of asset health, which enables the Company to proactively prevent high-impact equipment failures that would result in substantial

customer interruptions and materially reduced system resiliency. As shown in Figure 27 above, 27% of HVD substations have either moderate or high concerns regarding asset health. This level of asset health represents a substantial and unacceptable risk to the Company's system. Without targeted investment in this sub-program, these degraded assets will continue to age, increasing the probability of critical failures that result in large, complex outage events. While HVD substations are not currently the largest contributor to systemwide SAIDI, their strategic importance to system reliability is disproportionately high. Investment in HVD Substations Reliability therefore provides systemwide benefits that far exceed the asset class itself, strengthening backbone resiliency and reducing the risk of large-scale service disruptions.

Q. Does the Company have quantified benefits from its proposed investments in this sub-program?

A. The projected customer outage minutes avoided from HVD Substations Reliability investments are discussed below and shown in Figure 29. Customer outage minutes saved are calculated based on assumptions for number of impacted customers, outage duration, failure rate, and the number of circuits impacted based on the substation configuration. Assumptions are based on historical actual failures vs. asset population, average number of customers impacted by substation events, and historical response duration. The table below illustrates the assumptions used to calculate avoided customer outage minutes and confirms that the Company's investment is a prudent and necessary action to reduce risk, protect customers, and uphold our system reliability. Absent this investment, customers would face significantly higher exposure to preventable outages, and the system's ability to maintain safe, reliable service would be materially diminished.

FIGURE 29

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Circuit Breakers	3900	240	0.00286
Bushings	2300	1080	0.028
HVD Animal Mitigation	5850	120	0.067
Potential Transformer ("PT") Replacements	2000	240	0.01
Station Transformer Replacements	5850	240	0.005
Substation Rebuilds	11700	240	0.028
Substation Switches	3900	250	0.021

Q. Can you provide more details on the circuit breaker and switcher replacement investment category?

A. Circuit breakers and circuit switchers are critical components of the HVD system, designed to minimize customer outage impact and mitigate equipment damage when the system experiences and clears an electrical fault. The replaced units are generally 1950s and 1960s vintage oil or gas circuit breakers, given their poor performance, asset health, and the increasingly limited availability of parts. In addition, there are some early models of circuit switchers (notably certain S&C models) that have been deemed obsolete and have been replaced under this program.

In the bridge period and test year in the instant case, the Company is planning to increase the number of circuit breaker and switcher replacements that it completes. The

Company's HVD substations contain a total of approximately 950 circuit breakers and 300 circuit switchers, each with an estimated lifespan of 30 years. In order to appropriately maintain asset health, the Company should be replacing an average of 42 of these components each year. However, over the last 10 years the Company has only averaged 14.8 replacements per year, contributing to the declining asset health scores discussed above as these components become increasingly difficult to maintain and repair as the parts and equipment to maintain these obsolete devices no longer exist.

Q. What are the risks if the Company does not increase investment in circuit breakers and switchers?

A. It is imperative to invest in circuit breakers and switchers to proactively avoid the in-service failure of these devices, because if they do not interrupt when a short circuit or fault occurs, it can result in catastrophic damage to the HVD system, wide-scale customer outages, and public safety hazards. One recent example of a breaker failure occurred in Battle Creek on April 12, 2024. The breaker exploded upon failure, spewing oil around the substation and causing a fire, which caused the failure of several other substation components. This resulted in service impacts to 13,700 customers for up to 22 hours. It took 10 months to repair the substation, with a heightened risk of additional customer outages occurring while the substation was out of service. A picture of this failure is included as Figure 30.

FIGURE 30



Q. What has been the Company's recent experience regarding the cost of circuit breakers and switchers?

A. From 2024 through 2026, the Company has experienced an approximately 20% increase in the cost of electrical components, including circuit breakers, switches, and switchgear systems, driven by sustained pricing pressure across the electrical equipment market, where suppliers continue to pass through higher production, import, and material costs.

A primary driver of this inflation is the significant increase in tariffs on steel and aluminum—critical raw materials for circuit protection and switching equipment. Tariff levels have risen significantly, directly increasing the manufacturing and import costs of these components. The electrical equipment sector is simultaneously experiencing shortages and substantial price inflation due to ongoing supply chain constraints, increasing reliance on imported subcomponents, and market volatility for commodities such as steel, aluminum, copper, and semiconductor-based parts. As a result, suppliers are applying

elevated surcharges and delivering greater variability in pricing, as well as extended lead times.

These pressures are further compounded by increasing industry demand driven by the deployment of smart grid technologies, expansion of renewable energy resources, and growth in automation and electrification. The rising adoption of advanced circuit protection and energy management systems is also contributing to higher demand for modern switchgear and circuit breaker technologies.

Given these market conditions — tariff escalation, raw material inflation, supply chain constraints, and strong sector demand — prices for circuit breakers, switches, and related electrical equipment have increased materially and are expected to remain elevated. The Company's 2026 procurement costs reflect these sustained pressures, resulting in the documented 20% increase in electrical component costs from 2024 to 2026.

Q. Can you provide more details on the transformer bushing replacement investment category?

A. Transformer bushing replacements include bushing types with high failure rates, such as Type U, and bushings with observed degradation as identified through testing and inspection. Type U bushings have been known to lose dielectric strength due to a design characteristic that can result in violent failure. This failure often results in oil spraying on equipment, possible Polychlorinated biphenyl ("PCB") contamination, and damage to the transformer and/or adjacent equipment which can cause multiple minutes of SAIDI per event. The Type U bushings are known industry-wide to have higher failure rates than average bushing failure rates. The Company has been systematically replacing Type U bushings for several years, based on customer impact and consideration of other scheduled

work in the substation to maximize workforce efficiency and utilization, and at this point Type U bushings have largely been retired from the Company's system. The Company is also focusing on replacing Type O+C bushings due to a known oil defect used in manufacturing. Some O+C bushing oil is contaminated with corrosive sulfur that leads to degradation of the conductor and condenser structure within the bushing. These can also fail violently, resulting in the same concerns noted above with the Type U bushings.

Q. Can you further explain the Company's approach to switch replacements in this sub-program?

A. The Company's rationale for switch replacements was given in Figure 26 above. In the bridge period and test year in the instant case, the Company is planning to increase its investment in switch replacements because many existing switches are obsolete, have higher failure rates, and are increasingly difficult to operate safely and reliably. Aging switch mechanisms are often difficult to operate during outage events, which limits the Company's ability to sectionalize circuits and results in longer customer interruptions. Additionally, replacement parts for older switch models are exceedingly difficult to obtain, making repairs more costly and less effective. Proactively replacing these end-of-life switches improves system reliability, shortens outage durations, enhances operational safety, and aligns with the Company's long-term asset management strategy.

Q. Can you further explain the Company's approach to other targeted replacements in this sub-program?

A. The Company's rationale was explained in Figure 26 above. In the bridge period and test year in the instant case, the Company is planning to increase the amount of work being done in other targeted replacements. The increase is primarily due to new projects to install

animal mitigation, and new projects to install mobile transformer pads in order to better support system operability and to prepare for future transformer replacements.

Q. How did the Company develop the projected expenditures for the bridge period and test year in this sub-program?

A. Spending is based on the projected number of projects in each substation reliability category. Project costs were determined based on historical actual costs of comparable projects of similar scope.

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Substations Reliability sub-program?

A. The Company is projecting HVD Substations Reliability capital expenditures of $25,729,000 in the bridge period and $46,180,000 in the test year as shown in Exhibit A-87 (EMD-3), line 19. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 31 below. Planned projects are listed in Exhibit A-156 (KKL-3), pages 3-5, for the bridge period and in Exhibit A-157 (KKL-4), page 2, for the test year.

The HVD Substations Reliability sub-program provides a clear example of investments that do not necessarily have consistent, linear spending throughout the year on a month-by-month basis, which I discussed earlier in my direct testimony. The Company is limited in its ability to work on HVD substations during the peak summer load season to reduce the risk of overloads and customer outages while substation equipment is removed for service for work.

FIGURE 31
HVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Anticipated Customer Minute Savings	Test Year Capital	Test Year # of Units	Anticipated Customer Minute Savings
Circuit breaker/switcher replacements	$14,374,000	47	112,944	$18,477,000	35	80,228
Transformer bushing replacements	$216,000	1	69,552	$1,747,000	9	278,208
Switch replacements	$1,245,000	29	59,378	$2,483,000	56	114,660
Other	$5,639,000	25	188,136	$15,080,000	76	661,442
Imminent Failure Replacements	$4,255,000	35	235,200	$8,393,000	57	264,011
Total	**$25,729,000**			**$46,180,000**		

Q. What has been the historical actual spending in the HVD Substations Reliability sub-program for the past five years?

A. The historical actual costs by investment category for the HVD Substations Reliability sub-program are shown below in Figure 32.

FIGURE 32
HVD SUBSTATIONS RELIABILITY HISTORIC EXPENDITURES

2021	2022	2023	2024	2025	5-Year Average
$3,456,000	$3,993,000	$3,262,000	$5,715,000	$23,161,000	$7,917,000

Q. How would these historical expenditures look if they accounted for work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program?

A. If one looked at the historical investments in HVD substations that were made in the former HVD Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 33 below.

FIGURE 33
HVD SUBSTATIONS RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2021	2022	2023	2024	2025	5-Year Average
HVD Substations Reliability Historical	$3,456,000	$3,993,000	$3,262,000	$5,715,000	$23,161,000	$7,917,000
HVD Substations Rehabilitation Historical	$5,211,000	$4,712,000	$4,826,000	$4,403,000	$0	$3,830,000
Total	$8,667,000	$8,165,000	$8,088,000	$10,118,000	$23,161,000	$11,747,000

Q. How do the projected bridge period and test year investment compare to historical investment in this sub-program?

A. As discussed above, the Company is increasing its investments in certain investment categories in order to address asset health risks with those types of assets. The bridge period and test year in this case in this sub-program reflect those increases.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Many projects in this sub-program often include additional requirements beyond just the basic asset investment. This is common when system outages or reconfigurations are needed to allow workers to perform work on these assets safely. As these outages and

reconfigurations are sometimes difficult to schedule, when they do take place additional scope can be added to optimize the work that can be accomplished during a system reconfiguration or scheduled outage. For example, switches are often replaced when work is being done to replace a circuit breaker, as work conditions are ideal for addressing the switches while the breaker is being replaced. The historic unit costs for each investment category in the HVD Substations Reliability sub-program are included in Figure 34 below.

FIGURE 34
UNIT COSTS FOR HVD SUBSTATIONS RELIABILITY

Investment Categories	2021	2022	2023	2024	2025
Circuit breaker/switcher replacements	$116,673	$118,220	$157,560	$132,986	$334,035
Transformer bushing replacements	$107,997	$105,017	N/A	$136,738	$100,292
Switch replacements	$47,331	$41,328	$42,269	$108,397	$117,281
Other	$5,698	$51,840	$16,642	$40,293	$151,763

Q. Why do transformer bushing replacements not have a unit cost in 2023?

A. In 2023, there were no bushing replacement projects completed in this sub-program. All bushing replacements occurred on failed bushings or as part of projects in the former HVD Lines and Substations Rehabilitation sub-program, and the Company did not break out these unit costs in that sub-program.

Q. Please explain any variation in unit costs year-over-year.

A. Unit costs vary from year to year, as the apparent unit costs in this sub-program represent total project costs, not necessarily the cost to replace a single unit of equipment. Projects in this sub-program can vary greatly in scope, from a single piece of equipment being replaced to multiple pieces depending on the health of the assets at the substation. This is especially true for circuit breaker and circuit switcher projects. In addition to the cost issues discussed

earlier in my testimony, these projects require a significant amount of clearance to perform the work. Because of this, the Company expects to replace more than just individual breakers or switchers on the project. These projects will have expanded scope to include bus work modifications, additional switch replacements, and adjacent wiring to the control enclosures. These issues have caused unit cost increases for circuit breakers and circuit switchers.

Additionally, the "Other" investment category has included a wide range of types of projects over the years, making year-to-year cost comparisons difficult on a per-unit basis. That said, certain types of projects in this category have faced cost pressures. For example, material and contractor costs for station battery and fence projects have increased by at least 300%, and in some cases as much as 1,200%. Furthermore, many of the Company's station battery replacements now involve moving the batteries to a new control enclosure with corresponding wiring and panel work, increasing the costs of those projects.

c) <u>Transformer Bank Replacements and Substation Rebuilds</u>

Q. Please explain the Transformer Bank Replacements and Substation Rebuilds sub-program.

A. The Transformer Bank Replacements and Substation Rebuilds sub-program is dedicated to 1) the capital repair or replacement of HVD and SEC substation equipment (primarily large substation transformers ranging in size from 2 MVA to 100 MVA), and 2) rebuilds of entire substations. Both types of work typically consist of large projects that take place over multiple years in stages, with costs incurred across multiple years before the project is complete.

Q. Why does the Company replace large substation transformers and rebuild HVD and SEC substations?

A. When the asset health of an entire substation or of a large transformer within a substation deteriorates, the Company replaces them to reduce the risk of assets failing and causing impacts to customer reliability. Replacing these assets proactively prevents long duration outages that can often be 18-24 hours in length as the replacement of these assets often requires the Company to use an emergency mobile substation set. A mobile substation consists of substation equipment on a trailer that can be used to maintain service to an area while work is being done inside a substation. In an emergency situation when a major failure in a substation has occurred it can often take 18-24 hours to deliver and hook up a mobile substation, which can lead to two or more SAIDI minutes per incident. As identified in the Reliability Roadmap, many substation assets have outlived their initial intended lifespan, with a significant percentage of HVD substations facing high or moderate asset health concerns. While maintenance and inspection practices have, to date, allowed these assets to perform beyond their normal end of life, substation rebuilds and transformer replacements are needed to address these higher-risk assets.

Q. Are these projects larger and longer-term than projects in the HVD Substations Reliability sub-program?

A. Yes. These are major investments that require multiple years to plan, engineer, and secure equipment. A transformer can take between two and four years to obtain after ordering, with costs ranging anywhere from $1 million to $6 million, depending on size, technical scope and voltage rating. The Company uses strategies including leveraging existing relationships and executing contractual slot agreements to hedge demand and keep pace in

the market to lock in pricing. The multi-year nature of these projects means that different project stages can take place in different years. For example, one year may involve ROW procurement, another year may involve material procurement, another year may involve construction, etc. The multi-year planning component of these large projects makes it particularly important for the Company to have predictably and consistently approved cost recovery on a year-to-year basis.

Q. How does the Company determine if it will rebuild an entire substation or just replace transformers within the substation?

A. Multiple factors are taken into consideration when deciding to replace a transformer or rebuild a substation. If a transformer bank and bushings are deteriorated, but the rest of the substation is still in good operating health, then the Company will opt to replace the deteriorated transformer. If multiple components of a substation are deteriorated, it becomes more economical for the Company to rebuild the station instead of replacing a large number of components individually. Figure 35 below shows an illustrative example of the asset health model for HVD substations. In this example, *Sub A* would be a strong candidate for a full rebuild, as the Company would need to address the transformers, breakers, switches, and structure or concrete damage. Conversely, *Sub B* would be a likely candidate for a transformer bank replacement, as the primary driver of the score for that station is the failing health of the transformer bank itself. *Sub C* would be a candidate for targeted minor reliability projects like a single breaker replacement or correction of an infrared anomaly.

FIGURE 35
ILLUSTRATIVE SUBSTATION ASSET HEALTH MODEL

Category	Points per Occurrence	Sub A	Sub B	Sub C
AC/FP/REC Wound	15	0	0	0
Insulation Degradation	10	1	1	1
Oil or N2 Leaks	5	1	1	0
Transformermer Internal Infrared	10	0	1	0
DGA Score	30	1	0	0
Brand A Bushing Issue	10	1	0	0
Brand B Bushing Issue	10	0	0	0
Infared Anomalies P1 or P2	10	0	1	0
Doble or Electrical Testing Issues	10	0	1	0
Transformer & Bushings Total		55	45	10
Reg/LTC Oil Analyses TOA Code 3/4	25	1	0	0
Infrared Anomalies P1 or P2	20	0	0	0
Reg/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3ph Reg or LTC Demand Order	10	1	0	0
Breaker Oil or SF6 Gas Quality / Leaks	15	0	1	1
Infrared Anomalies P1 or P2	15	0	0	0
Maintenance / Replacement Priority	10	0	0	0
Oil & Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSW/VSW Issues	15	1	0	0
SPT Watch List	10	2	1	1
Str & Concrete	5	1	0	0
Other	5	0	0	0
Infrared Anomalies P1 or P2	15	0	1	1
Operations Limiting Equipment	20	1	0	0
Station & Other Totals		60	30	30
Total Normalized Score		100	56.8	32.4
Gross Total		185	105	60

Q. How are investments in HVD substation transformer replacement projects aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company would need to replace an average of 12 transformers yearly between HVD and strategic customer substations to address transformers in poor asset health. Because these large transformers have a long lead time, the number of replacements completed in a given year may vary from year to year. In the

instant case, the Company is planning to complete the replacement of 11 transformers in the bridge period (10 through transformer bank replacements and one in a substation rebuild) and five transformers in the test year (four in transformer bank replacements and one in a substation rebuild).

Because it can take more than two years to obtain a single transformer, the Company also places orders for transformers ahead of time to ensure they will be available in the years beyond this current case to support the increased replacement levels described in the Reliability Roadmap. The Company then makes "progress payments" on these transformer orders to ensure their timely delivery from the manufacturer. Making progress payments allows the Company to ensure it has the appropriate supply of transformers in the future. In Exhibit A-156 (KKL-3), page 6, and Exhibit A-157 (KKL-4), page 3, each transformer replacement line item with a "0" in the units column indicates that progress payments are being made on transformers in the relevant period.

Q. How are investments in HVD substation rebuilds aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company will complete approximately two to four HVD and strategic customer substation rebuilds per year. HVD substation rebuilds are generally very large projects that span two to three years, so in any given year the Company will likely be performing some work on more than two projects at once, and the Company may not always bring two projects a year to final completion. Also, as noted above, substation rebuilds themselves require new transformers, so the number of substation rebuilds can be inversely correlated with the number of transformer replacement projects.

In the bridge period in this case, the Company is performing work on five different substation rebuild projects (see Exhibit A-156 (KKL-3), page 6):

- Buskirk Creek Substation: This is a brand-new substation on a new parcel that will replace the Wayland Substation once it is complete. Scope of work in the bridge period will include labor and materials to complete this new substation. Final checkout and asset-in-service is scheduled for mid-year 2026.

- Armory Substation: This is a brand-new substation on a new parcel that will replace the Alma Substation once it is complete. Scope of work will include transformer procurement costs of two units, property acquisition, environmental assessment, permitting expenses, land survey, and engineering costs.

- Royal Substation: This is a brand-new substation to replace the existing Blackstone substation on a new parcel. Scope of work will include transformer procurement costs for two units, property acquisition, environmental assessment, permitting expenses, engineering costs, and land clearing.

- Lenawee Stamping Substation: This project began as a transformer bank replacement. However, after further investigation, the obsolete wood-pole construction of the substation structure is in poor condition as well, so the Company is shifting to rebuilding the substation with an updated steel structure design. Scope of work in the bridge period will include transformer procurement and engineering costs.

- Dearborn Machine Substation: This project also began as a transformer bank replacement. However, similar to Lenawee Stamping, the substation has an obsolete wood pole construction that is in poor condition, so the Company is shifting to rebuilding the substation with an updated steel structure design. Scope of work in the bridge period will include transformer procurement costs.

In the test year in this case, the Company is performing work on four different substation rebuild projects (see Exhibit A-157 (KKL-4), page 3):

- Armory Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured. Labor and materials to construct the first of two transformers will also be included. Final checkout and asset in-service for this first transformer is planned for late 2028, while labor and materials to complete the second transformer will be beyond the test year.

- Royal Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured as well

as grading of the new site. Also, labor and material costs to begin construction will be spent during the test year. The remainder of construction, final checkout, and substation asset in-service are planned to occur by end of 2028.

- Lenawee Stamping Substation: Scope in the test year includes continued transformer procurement and engineering costs as well as most of the labor and materials to complete this rebuild project. Final checkout and asset in-service is planned for mid-2028.

- Dearborn Machine Substation: Scope in the test year includes continued transformer procurement costs as well as a portion of the engineering costs. Labor and material costs to complete the project will continue beyond the test year.

Q. Does the Company consider any alternative approaches to its substation investments in this investment category?

A. As discussed above, the first option is to address only the major assets that are failing on an individual basis. If this can be done, it improves the overall health of the station with the minimum required scope and cost while addressing the risk in the most immediate timeframe. Full substation rebuilds are only done when there are multiple failing assets, which is then a more cost-effective option than replacing individual components. In the concept approval process, the Company reviews alternatives to address the main concerns at each site, and an alternative is selected that best addresses the main asset health concern while also minimizing impact to the grid and external stakeholders.

For the substation rebuild replacement projects, the projects were selected from a list of the 25 HVD bulk power substations evaluated as the highest priorities based on their asset health considering inputs from multiple groups within the Company. Adjustments to the plan were then made based on geographic locations, other known large projects in progress for the Company and the Michigan Electric Transmission Company ("METC"), and the ability to schedule outages. Rather than select from the list of possible substation locations for rebuilds, the other option would be to attempt to run each HVD substation

component to failure, but this would result in more customer outages and increased costs to the customer in the long run as equipment would have to be replaced on a demand basis. Transformer replacement projects were selected in a similar manner, but prioritizing units with failing test data. Like the HVD substation rebuilds, the other option would be to run these units to failure, which would result in extended customer outages, due to the long lead time for manufacturing replacement units (there are a limited number of spare HVD transformers in stock), and the small number of mobile substations available for HVD voltages. When transformers fail prior to a scheduled replacement, it creates a significant strain on completing other planned work, as often the Company may have to reallocate a transformer meant for a replacement project to address an actual failure. This delays the benefit of completing the planned projects and causes cascading issues of rework for materials and resource allocation. At best, the result would be higher costs for customers for the replacement of these units since the work would be unplanned.

In the instant case, the Armory Substation (replacing Alma Substation) and Royal Substation (replacing Blackstone Substation) replacement projects are among the Company's 25 largest overall test year distribution projects, and the associated concept approvals are provided to the parties in the Company's Part III filing requirements, which show additional details around how these projects were selected.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, in the Transformer Bank Replacements and Substation Rebuilds sub-program?

A. The Company is projecting Transformer Bank Replacements and Substation Rebuilds capital expenditures of $26,605,000 in the bridge period, and $37,155,000 in the test year as shown in Figure 36 below.

Transformer Bank Replacements and Substations Rebuilds is another sub-program that provides a clear example of investments that do not necessarily have consistent, linear spending throughout the year on a month-by-month basis, which I discussed earlier in my direct testimony. As with HVD Substations Reliability, the Company is limited in its ability to work on HVD substations during the peak summer load season to reduce the risk of overloads and customer outages while substation equipment is removed for service for work.

FIGURE 36
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Benefit (Customer Minutes)	Test Year Capital	Benefit (Customer Minutes)
Large Transformer Replacements	$12,044,000	42,131	$4,755,000	35,102
Progress Payments on Transformers	$4,223,000	N/A	$11,615,000	N/A
HVD Substation Rebuilds projects	$10,338,000	235,872	$20,785,000	157,248
Total	**$26,605,000**	278,003	**$37,155,000**	192,350

Q. Please list any projects that make up the requested spending level for the Transformer Bank Replacements and Substation Rebuilds sub-program during the bridge period and test year.

A. Identified projects for this sub-program are listed in Exhibit A-156 (KKL-3), page 6, for the bridge period and in Exhibit A-157 (KKL-4), page 3, for the test year. Exhibit A-156 (KKL-3), page 6 shows the one expected Substation Rebuild (Buskirk) and 10 transformer replacements expected to be completed in the bridge period, while Exhibit A-157 (KKL-4), page 3 shows the one expected Substation Rebuild (Armory) and four transformer replacements expected to be completed in the test year. Both exhibits detail the expected spend on transformer progress payments that will be made in their respective periods toward equipment procurement for projects expected to be completed between 2028 and 2030.

Q. Please provide an overview of historical spending for the investment categories in this sub-program.

A. The historical actual spending, from when work was included in the former HVD Lines and Substations Rehabilitation sub-program, is shown in Figure 37 below. Note that this figure does not represent all historical spending in the former HVD Lines and Substations Rehabilitation sub-program, only the spending on transformer bank replacements and on HVD substations rebuilds.

FIGURE 37
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS HISTORICAL SPENDING

Investment Categories	*2021*	*2022*	*2023*	*2024*	*2025*	*5-Year Average*
Large Transformer Replacements	$3,598,057	$4,682,117	$6,240,187	$2,934,464	$12,912,332	$6,073,431
HVD Substation Rebuilds	$10,845,480	$15,847,961	$6,081,940	$5,992,604	$9,372,898	$9,628,177

Q. How were the bridge period and test year spending amounts determined for the HVD substation replacement projects investment category?

A. For HVD substation rehabilitation work, spending for the bridge period is based on projects identified in Exhibit A-156 (KKL-3), page 6. Spending for the test year is based on projects identified in Exhibit A-157 (KKL-4), page 3.

Q. How will customers benefit from investments in this sub-program?

A. Benefits in this sub-program fall into a few categories. First, these investments will deliver the customer-minute benefits summarized in Figure 34 above. The projects address the assets in the worst health at the Company's most critical substations. By replacing transformers, and by replacing both transformers and other equipment when performing a rebuild, the Company is ensuring that the substation is ready to serve the area for the next 50+ years.

Q. What are the historical unit costs for this sub-program?

A. Because this sub-program consists of a small number of large projects that often take place over multiple years, there is not a meaningful way to calculate historical annual unit costs for this sub-program.

d) LVD Substations Reliability

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Reliability sub-program.

A. The LVD Substations Reliability sub-program ensures the long-term safe and reliable operation of LVD substations, which are the interface point between the HVD lines and LVD lines on the Company's system. The Company's LVD Substations Reliability investments significantly reduce the risk of a customer experiencing a long duration outage. While customers in more urban areas often can transfer to an adjacent substation through LVD line switching in the event of a failure, for customers in more rural areas, there is often no ability to transfer substations. This increases the likelihood that an outage due to LVD substation equipment failure could be longer in duration. To mitigate this risk, the LVD Substation Reliability sub-program has invested in several categories, including:

(i) new or rebuilt substations;

(ii) mobile substations;

(iii) animal mitigation;

(iv) substation transformer replacements;

(v) voltage regulator replacements; and

(vi) Distribution Supervisory Control and Data Acquisition ("DSCADA") projects.

Q. Please explain why it is necessary to install new substations or rebuild existing substations to enhance LVD substation reliability.

A. New substations with new line circuits improve reliability by reducing the overall length of circuits. Shorter circuit miles reduce outage exposure, and new circuits allow for modified line protection schemes that can reduce the number of customers that experience outages

during outage events. New substations provide additional capacity that can be used for planned and emergent customer transfers to minimize outage duration, and distribution automation schemes can be installed to transfer customers between substations during outage events. Before a new substation is considered, a study is completed to compare the SAIDI, System Average Interruption Frequency Index ("SAIFI"), and CAIDI benefits along with the economic costs of the new substation alternative to traditional line solutions, and to consider long-term system capacity needs to optimize new substation locations. A new substation may be installed if the system reliability improvements and economic benefits are comparable to or exceed traditional line solutions.

Substation rebuilds are necessary due to working clearance constraints within the compact designs of substation structures commonly constructed in the 1950s and 1960s. Operations and maintenance personnel are not able to operate or replace equipment without de-energizing the entire substation due to unacceptable working distances from energized components. This results in additional costs to use a mobile substation for planned projects or increases restoration time and the number of customer outages needed for emergent work, degrading the reliability of service provided to customers. Because of the new design and expanded dimensions, modern electronic reclosers and voltage regulators do not fit within these compact structures without violating working clearances or electrical code clearances.

Q. What are mobile substations?

A. Mobile substations are compact semi-trailer mounted substations that can be moved around the service territory to restore interrupted service for long duration substation equipment repairs and replacements or to maintain service to customers during planned substation projects.

Q. Does installation of mobile substations improve reliability outcomes, including those set forth in the Company's longer-term distribution strategy?

A. Yes. Mobile substations are used to maintain service to customers during planned substation projects, for imminent failure concerns before interruptions occur, and to restore interrupted service, limiting the negative reliability impacts.

Q. What is the purpose of investment in animal mitigation measures?

A. Animals that meet energized substation components cause service interruptions and equipment damage. The purpose of each animal mitigation project is to keep animals, such as squirrels and raccoons, out of the substation, and to insulate equipment to extend touch potential if an animal gets into a substation, with specific measures chosen based on substation characteristics. Animal mitigation measures are part of the substation engineering design standards and are installed in all new substations and substation rebuilds. Common animal mitigation measures include:

(i) one-inch mesh fence (squirrels can squeeze through larger mesh);

(ii) concrete gate foundations (minimizes gaps and frost heave that create gaps over time);

(iii) polycarbonate panels (three-foot panels installed at the top of the fence to mitigate animals from climbing over the fence);

(iv) pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation);

(v) interior and exterior stone (eliminate gaps at the fence bottom to mitigate animals from crawling under the fence); and

(vi) bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components should an animal climb on equipment.

The Company also typically clears vegetation within 10 feet from the substation fence, except if a city or township requires vegetation to be closer for screening purposes or if the

substation fence is within 10 feet of the property line, and the adjacent property has vegetation up to the property line. The Company's animal mitigation standards do not include measures to prevent bird intrusions because birds can fly over fences and barriers, but mitigation measures such as bushing guards can mitigate touch potential on energized components.

FIGURE 38
DAMAGE FROM ANIMAL CONTACT



In 2012, the Company began animal mitigation investments to install animal mitigation at all LVD substations, and updated engineering design standards to incorporate animal mitigation into all new substations and substation rebuilds; animal mitigation is now a standard business practice. When this initiative started, approximately 12.5% of LVD substations had the common animal measures described above. This initiative will be completed in 2026. With the completion of the 20 animal mitigation projects planned for the bridge period, 790 LVD substations will have animal mitigation (94.5%). Of the remaining 46 substations that will not have animal mitigation, 28 substations will have animal mitigation installed on future rebuild projects, three substations are planned for

retirement, and 15 substations have unique site conditions or pole-mounted platform designs where all of the common animal mitigation measures would not be effective or cannot be installed; but these substations do have partial animal mitigation measures where practical, such as bushing guards. With the animal mitigation program ending in the bridge period, there are no animal mitigation projects planned for the test year.

Q. How do the Company's proposed substation transformer replacement projects impact customer reliability?

A. Replacement of substation transformers that show evidence of degradation before failure occurs prevents service interruptions. The length of interruption due to a substation transformer failure can be extensive. Restoration of customers after a failure can take up to 24 hours if installation of mobile substation is required on an emergency basis, while a proactive replacement prior to failure can result in no customer outage impact. Further, the failure of a substation transformer in service can cause employee and public safety hazards as well as environmental risks due to spilled oil.

Q. How do the Company's proposed substation voltage regulator replacement projects impact customer reliability?

A. Replacing substation voltage regulators that show evidence of degradation before failure occurs prevents service interruptions, improves service quality, and prevents customer equipment damage that can occur with unregulated service voltage.

In recent years, the Company has tempered its investment in substation voltage regulator replacements in order to direct investment towards other higher priority sub-program investment categories. With the completion of animal mitigation and DSCADA work in the bridge period, the Company plans to ramp up voltage regulator replacements in

the test year by replacing 60 voltage regulators (approximately 1.14% of population). Oil test data has shown evidence of internal degradation for these 60 voltage regulators that the Company has identified for replacement.

Q. Has the Company recently added any new types of investment to the LVD Substation Reliability sub-program?

A. Yes. Starting in 2024, DSCADA work was moved to the LVD Substation Reliability sub-program. Projects to install DSCADA systems in existing LVD substations were previously part of the Grid Automation sub-program and are now an investment category within the LVD Substation Reliability sub-program.

Q. What is DSCADA?

A. The Company has been installing DSCADA on its LVD substations for several years, and now considers it a standard business practice, which is why it is no longer considered a Grid Automation effort and has been moved into this sub-program.

DSCADA is a foundational system that gathers real-time grid data and provides substation device remote control capability. When DSCADA is installed at a substation, it includes a Remote Terminal Unit ("RTU"), a local device that facilitates communications with substation devices, and remote software systems. The communications component uses a cellular modem to transmit more than 300 data points within the substation to the ADMS. DSCADA investment includes the required construction and installation of automation equipment at the substation, as well as adding smart devices and controllers to core substation equipment.

In 2012, the Company began DSCADA investments to install DSCADA at all LVD substations, and updated engineering design standards to incorporate DSCADA into all new

substations and substation rebuilds. This initiative will be completed in 2026. With the completion of the 12 DSCADA projects for the bridge period, approximately 743 LVD substations will have DSCADA (88.9%). Of the remaining 93 substations that will not have DSCADA, 71 substations will have DSCADA installed on future rebuild projects or projects within the other sub-programs, three substations are planned for retirement, and 19 substations have unique designs where DSCADA would not be practical, such as welder substations. With the DSCADA program ending in the bridge period, there are no DSCADA projects planned for the test year.

Q. How does the Company identify LVD Substations Reliability projects?

A. The Company uses several inputs and analyses to determine how to best target LVD Substations Reliability issues. These inputs help identify specific areas to target investments based on probability of future issues and help to prioritize projects that will deliver the greatest reliability improvements based on SAIDI and SAIFI and are tracked in the Asset Health model in a similar manner to HVD substations, described above. These inputs include:

- LVD circuit planners – Analyze historical outage trends on the LVD lines system to identify areas of greatest reliability concern based on total number of outages, trends in reliability performance, and potential reliability impact;
- Input from field operations and other departments – Inform substation planning engineers on operational concerns and system constraints identified during substation inspections, as described by Company witness Duke, that may trigger necessary projects, such as working clearance constraints;
- Equipment trend data – Planned replacement of substation equipment may be triggered with trend data that indicates degrading equipment condition but has not reached a concern of imminent failure; and
- Mobile substation planning – Includes assessing and maintaining the Company's mobile substation fleet based on historical project usage and the purchase of new mobile substations to replace those which have become uneconomical to repair.

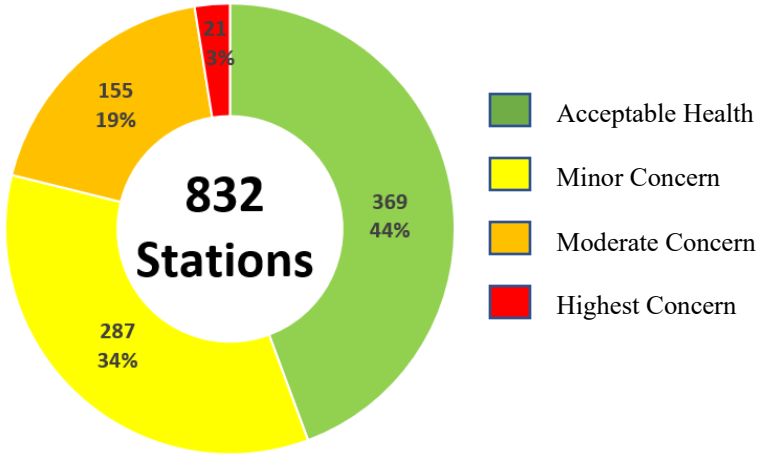
Q. Does the Company consider non-wire alternatives ("NWAs") in the LVD Substations Reliability sub-program?

A. Not presently. NWAs are not mature enough to adequately address the specific reliability issues that are the focus of this sub-program. As discussed by Company witness Duke, the Company is working to undertake the expedited pilot process to better understand how non-wire solutions ("NWS") can be utilized for reliability.

Q. How are the projected LVD Substation Reliability expenditures aligned with the Reliability Roadmap?

A. Figure 39 below, taken from the Reliability Roadmap, shows that a large percentage of LVD substations have at least some concerns in the Company's assessment of their asset health. Of the total population of LVD substations, 3% are a high priority for component repair or replacement and another 19% have a moderate level of risk. As stated in the Reliability Roadmap, the Company plans to address these asset risks through a comprehensive plan to replace all components that are beyond end-of-life, including building and rebuilding substations, a plan which will result in two fewer LVD substation outages per year. Because LVD substation outages can impact a large number of customers, this will provide a meaningful reliability benefit. As outlined in the Reliability Roadmap, this effort involves a ramp-up in LVD substation investment in both this sub-program and the LVD Substations Rehabilitation sub-program.

FIGURE 39
LVD SUBSTATION HEALTH



Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Reliability sub-program?

A. The Company is projecting LVD Substations Reliability capital expenditures of $65,664,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 18, column (k), and $42,880,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 18, column (l). The Company's historical actual spending in the LVD Substations Reliability sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 18. Overall bridge period and test year investment levels are commensurate with those in 2025.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as shown in Figure 40 below. Please note that the number of units in each column refers only to the number of units that will be field complete in the relevant period; as discussed below, many projects in this sub-program extend across multiple years, and these are not counted among the units listed here.

FIGURE 40
LVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
New or rebuilt substations	$28,567,000	7	$14,061,000	3
Mobile substations	$7,382,000	0	$6,359,000	0
Animal mitigation	$3,594,000	20	$0	0
Regulator replacements	$360,000	6	$3,600,000	60
Transformer replacements	$19,798,000	4	$18,860,000	1
DSCADA Projects	$5,963,000	12	$0	0
Total	**$65,664,000**	**49**	**$42,880,000**	**64**

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Reliability sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-156 (KKL-3), pages 7 and 8, and for the test year, listed in Exhibit A-157 (KKL-4), page 4. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes, the Houghton Lake, Waldron, Mobile Substation 26, Mobile Substation 28, and Mobile Substation 29 projects listed for the bridge period in Exhibit A-156 (KKL-3), pages 7 and 8, and for the test year listed in Exhibit A-157 (KKL-4), page 4, will span multiple years due to construction scheduling and mobile substation progress payments occurring in the bridge period and test year.

The Onsted, Twin Lake, Alcona Dam, Greenbush, Greenspire, Manton, North Muskegon, Oak Street, Pewamo, Pierson, Pullman, Round Lake, Thornapple, Westphalia, and Withey Lake substation rebuild projects and the Broadmoor TB3, Broadmoor TB4, Allendale Pumping, Bailey, Bayberry, East Grant, Forest Grove, Frankfort TB1, Frankfort TB2, Frost, Fulton, Hopkins, Kelloggsville TB1, Kelloggsville TB2, Kendall, Lake Shore, Lee Street, Mayfair, Morrell, Muskegon Heights TB5, Muskegon Heights TB6, Muskegon Treatment TB1, Muskegon Treatment TB2, North Kent TB1, North Kent TB3, Reading, Red Cedar, Richland, Sheridan, Travis, Walnut, Williams TB1, and Williams TB2 transformer replacement projects listed for the bridge period in Exhibit A-156 (KKL-3), pages 7 and 8, and for the test year listed in Exhibit A-157 (KKL-4), page 4 are planned in years beyond the test year, but will span multiple years due to transformer progress payments occurring in the bridge period and test year.

Because it can take more than two years to obtain a single transformer, the Company has placed transformer orders ahead of time to ensure they will be available in the planned project years. The Company then makes "progress payments" on these transformer orders to ensure their timely delivery from the manufacturer. Making progress payments allows the Company to ensure it has an adequate supply of transformers for the planned projects.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Reliability sub-program?

A. Customer benefits in this sub-program can be categorized as reducing customer-outage-minutes or as service quality. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. Since 2012, when the Company increased animal mitigation installations at LVD substations, approximately 92% of

substations equipped with the common animal mitigation measures have experienced no animal-caused outages since the installation was complete.

As discussed above, DSCADA has been transferred to this sub-program, and the control and data-gathering capability of DSCADA lets the Company obtain grid data that is analyzed to make decisions on what field devices need adjustments to optimize performance. Expanding DSCADA broadens the customer base that can benefit from improved customer reliability and reduced outage durations. By adding substation communications, the benefits associated with volt-var optimization ("VVO"), conservation voltage reduction ("CVR"), distributed energy resource ("DER") integration, automation transfer recloser ("ATR") loops, and voltage regulator controllers will benefit more customers. DSCADA reliability benefits are driven by reduced outage response time and faster restoration via remote operations.

Overall, the benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibit A-156 (KKL-3), pages 7 and 8, and for the test year, listed in Exhibit A-157 (KKL-4), page 4. Types of benefits identified on the exhibits, and summarized in Figure 41, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete; and
- Service Quality – quantifies the number of customers benefiting from a project to improve the voltage to ensure that equipment operates properly as designed, keeping service point voltages within the ranges customers expect.

FIGURE 41
LVD SUBSTATIONS RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	19,886,027	3,593,340
Service Quality; number of customers	-	21,444

Q. Are there customer reliability benefits from mobile substation purchases?

A. Yes. Mobile substations are purchased to support planned substation projects, planned lines projects, imminent failure concerns before customer outages occur, and unplanned failures to restore service to customers. Accordingly, it is difficult to predict where and when each mobile substation will be used to calculate the specific benefits.

Q. Please explain the historical year-over-year variation in spending in this sub-program.

A. In 2021, the Company invested in 50 animal mitigation projects and seven transformer replacements. In 2022, the Company invested in four substation rebuilds, 31 animal mitigation projects, and three transformer replacements. In 2024, the Company moved three work items from the HVD Lines and Substation Capacity and Grid Automation sub-programs to the LVD Substation Reliability sub-program, as discussed above. In 2025, the Company started the Houghton Lake substation project which included substation construction, multi-mile HVD line construction, and easement purchases for the multi-mile HVD line; Mobile Substation 26 and Mobile Substation 29 progress payments; and progress payments for 48 new transformers that are being planned for 2026 - 2030 substation rebuilds and transformer replacement projects. These additional amounts are summarized in Figure 42 below, showing how spending increased from a little less than $20 million in years through 2024 up to $43 million in 2025.

FIGURE 42
LVD SUBSTATION 2025 VARIATION IN SPENDING

Project Investment	2025 Capital
Houghton Lake Substation	$10,271,000
Mobile 26 and Mobile 29 Progress Payments	$3,190,000
Transformer Progress Payments	$10,507,000
Total	**$23,968,000**

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. Average unit cost is not a good measure to predict the cost of an individual project in the new or existing substation rebuilds, animal mitigation, and transformer replacement investment categories due to specific work scopes needed for each project. New substation costs can vary based on things such as the substation design, electrical capacity required, and site conditions. Substation rebuild costs can vary based on whether a full rebuild or a partial rebuild is required and whether load transfers to an adjacent substation can be utilized or if a mobile substation is required to maintain electrical service during the rebuild. New substations and substation rebuilds that span multiple years also affect average unit cost when project spending occurs in multiple years. Animal mitigation costs can vary based on the substation physical size and whether full mitigation or partial mitigation measures are required. Transformer replacement costs can vary based on the electrical capacity and voltages of the replacement transformer and whether load transfers to an adjacent substation can be utilized or if a mobile substation is required to maintain electrical service during the replacement. Additionally, DSCADA project costs can vary based on the specific work scopes needed. For example, the project scopes for Baldwin and Ensley include six recloser replacements because the reclosers are an obsolete model, the obsolete controllers cannot

communicate with DSCADA communication, and mobile substations are required to replace the reclosers. The Baldwin transformer has also reached end-of-life and will be replaced while the mobile substation is onsite for the recloser replacements. Average unit cost does generally reflect the expected spending per project for the voltage regulator replacement investment category.

e) LVD Substations Rehabilitation

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Rehabilitation sub-program.

A. The LVD Substations Rehabilitation sub-program includes capital repair or replacement of LVD substation equipment that has not actually failed but has been assessed to be at imminent risk of failure, projects to address code violations, and projects to replace obsolete equipment. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning arresters, and switches that can no longer be purchased from manufacturers, have depleting inventory, and replacement parts can no longer be purchased.

Q. What are the inputs used to determine what equipment may be in an imminent failure status?

A. Imminent failures are identified by monitoring and tracking LVD substation equipment and components using various means of analysis such as dissolved gas analysis ("DGA") and infrared data. These analyses help to identify specific locations to target corrective action based on probability of an unplanned event, and to prioritize projects that will deliver the greatest reliability impact based on specific metrics (*e.g.,* SAIDI and SAIFI). Proactively replacing deteriorated equipment that is deemed as an imminent failure in advance of an actual equipment failure is more economical as it typically avoids customer outages and

costly overtime. Some imminent failures are identified through monthly visual patrols performed by the Company's Substation Operations group and are replaced through this program prior to failure. The cadence of the LVD substation equipment evaluation and inspection is found in Figure 43.

FIGURE 43
LVD SUBSTATION INSPECTION CADENCE

Inspection Task	Cadence	Actions Taken
All Station Components	Bi-Monthly	Visual inspection Routine patrol inspections
Entire Substation	Bi-Annually	Infrared inspection of entire substation
Protective Relays and Communication Systems	Dependent on relay model & failure history	Maintenance & testing performed
Station Batteries	Monthly	Voltage check
	Annually	Equalization
	Annually	Specific gravity reading
	4 Years*	Complete inspection
Power Transformers	Bi-Monthly	Visual inspection (including fans and pumps)
	Annually	Total combustible gas test (follow-up dissolved gas analysis tests, if warranted)
	Annually	Diagnostic Dissolved Gas Analysis of Load Tap Changer Oil (Transformers with Load Tap Changers Only)
	Annually	Diagnostic Dissolved Gas Analysis of mid-20th century vintage Allis Chalmers Transformers
	Bi-Annually	Diagnostic Dissolved Gas Analysis of Transformer Main Tank Oil (Transformers with Load Tap Changers Only)
	6 years**	Diagnostic dissolved gas analysis of transformer oil (Non-Load Tap Changer Transformers)
Motor Operated Air Break Switches (MOABS)	Annually	Test Operated (decoupled)
	4 Years**	Battery replacement
Single Phase Regulators	9 Years***	Limited program of dissolved gas analysis

*Or periodically as needed
**Or sooner if determined by combustible gas tests or high gas levels in previous tests
***Started in 2014

Q. Do any other operating organizations or departments provide input into this sub-program?

A. Yes. Input from operating organizations and other departments inform the substation planning engineers with operational concerns, system constraints, and regulatory changes that may trigger a need for replacement of obsolete equipment, replacement of imminent equipment failure, or substation modifications to comply with new regulatory requirements.

Q. What investment categories are included in the LVD Substations Rehabilitation sub-program?

A. The LVD Substations Rehabilitation sub-program includes:

(i) Allis Chalmers substation transformer replacements;

(ii) Equipment replacement and regulatory-related projects, which include end-of-life condition substation rebuilds, equipment at risk of imminent failure, addressing new regulatory requirements, and replacement of obsolete equipment such as reclosers, breakers, fuses, voltage regulators, lightning arresters, and switches; and

(iii) Recloser replacements. Though recloser replacements are a sub-set of the equipment replacements described above, obsolete/end-of-life recloser replacements are listed separately in Figure 42 due to the multi-year replacement plan described below.

Q. Please describe the Allis Chalmers substation transformer replacement investment category.

A. Allis Chalmers mid-20th century vintage substation power transformers were produced with a design deficiency associated with the top clamping structure of the transformer windings. The key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts

and arcing, which lead to excessive heating, creation of combustible gases, and eventual failure of the transformer.

Q. How many of these Allis Chalmers substation transformers are in-service at LVD substations and what has the Company's recent experience been with these transformers?

A. Going into 2026, the Company will have 31 of these Allis Chalmers units in-service in their original design, and another four rewound units in-service that are considered at risk of developing problems, for a total of 35 units at its LVD substations. From 2014 through 2018, approximately 28% of the substation transformer failures had been from this vintage and manufacturer, but increased monitoring and replacement resulted in no transformer failures from this vintage and manufacturer from 2019 through 2025.

Q. What has been the Company's recent performance in replacing Allis Chalmers substation transformers?

A. The Company has been replacing Allis Chalmers transformers as follows:

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Allis Chalmers Transformer Replacements	9	10	15	6	19	7	5	3	2

Q. Please explain the equipment replacement and regulatory-related projects investment category.

A. When a substation is at the end of its useful life and experiences substantial deterioration – becoming unsafe, no longer able to reliably operate, or some other issue – the Company may elect to rebuild the substation. However, the Company is not planning any end-of-life condition substation rebuilds in the test year. For regulatory-related projects, the Company is planning projects related to working space, which bring substations into compliance with National Electrical Safety Code ("NESC") Rule 125, section A, titled "Working space about

electric equipment: Working Space (600 Volts or Less)." When the Company was working to upgrade its telecommunications at its LVD substations in the late 2010s, it discovered that some of the substations did not meet the NESC working space requirements and began a process of addressing all of these working space issues by 2028. The Company has completed 57 of the 66 identified capital projects related to this working space issue at its LVD substations and plans to complete the remaining nine capital projects in the bridge period and the test year, as follows: six projects in the bridge period, one project in the bridge period in the System Protection sub-program, and two projects in the test year.

Q. How does the Company treat obsolete equipment as part of the equipment replacement and regulatory investment category?

A. When specific types of equipment can no longer be purchased from manufacturers, replacement parts can no longer be purchased, and inventory levels are depleted, equipment is classified by the Company as obsolete. Targeted replacements are implemented because new equipment may not fit into the same location without structural substation modifications due to physical size, mounting requirements, and electrical clearance requirements.

Q. Please explain the recloser replacements investment category.

A. In 2027, the Company will begin a recloser replacement effort to replace three recloser models that are no longer being manufactured and obsolete, starting with those reclosers that have reached end-of-life. The recloser models that have recently been classified as obsolete represent approximately 94% of the total recloser population of approximately 5,260 reclosers, with 8.04% of the obsolete recloser model types having reached end-of-life. The recloser replacement initiative will target approximately 400 recloser replacements

each year that have reached end-of-life, with the test year replacing 395 obsolete reclosers that have reached end-of-life (7.98% of the obsolete recloser population).

It is important to replace obsolete reclosers because replacement parts are not available and installation of newer reclosers often requires engineered structural changes to the substation. Replacing these reclosers after failure could result in lengthy outages to customers in order to retrofit new reclosers in their place or place the system into an abnormal condition that increases the number of customers that would be impacted during future outages until the reclosers are replaced.

Q. Are there any projects that span multiple years?

A. Yes. In Exhibits A-156 (KKL-3) and A-157 (KKL-4), the Company is listing all projects that will have some level of investment in the relevant period, but many projects that include investment will not be complete until a future point in time. The Fountain, Liberty, Muskegon Heights, Neff Road, and Steelcase projects, listed for the bridge period in Exhibit A-156 (KKL-3), page 9, and for the test year listed in Exhibit A-157 (KKL-4), pages 5 and 6, will span multiple years due to construction scheduling and transformer progress payments.

The Ballenger, Cooper, Fraser Pumping, GMI, Golden, Junction Pumping, Lyons, Mayfair, Nestrom, Ottawa Beach, Saginaw Street, Gladwin, Hart, Interlochen, Ionia Manufacturing, Fairbanks, and Port Calcite projects listed for the bridge period in Exhibit A-156 (KKL-3), page 9, and for the test year listed in Exhibit A-157 (KKL-4), pages 5 and 6 are planned in years beyond the test year, but will span multiple years due to transformer progress payments occurring in the bridge period and test year.

Because it can take more than two years to obtain a single transformer, the Company has placed transformer orders ahead of time to ensure they will be available in the planned project years. Making progress payments will allow the Company to ensure it has an adequate supply of transformers for the planned projects.

Q. What benefits will customers realize through the Company completing work, in the LVD Substations Rehabilitation sub-program?

A. This sub-program works to address areas in LVD substations where code violations are present, or where failures, and corresponding outages and customer interruptions, are particularly likely. Addressing degrading equipment reduces the likelihood of failure, resulting in fewer minutes per year of outages on average. The benefits for the bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-156 (KKL-3), page 9, and A-157 (KKL-4), pages 5 and 6. The types of benefits identified on the exhibits, and summarized in Figure 44, include:

FIGURE 44
LVD SUBSTATIONS REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	19,044,900	41,850,960
Regulatory Compliance projects	6	2

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Rehabilitation sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-156 (KKL-3), page 9, and for the test year, listed in Exhibit A-157 (KKL-4), pages 5 and 6. These exhibits also identify the location and benefits of the projects.

Q. Are there circumstances in which Allis Chalmers substation transformer replacements could be reprioritized?

A. Over the next several years (continuing beyond the test year), the Company plans to replace the 18 remaining Allis Chalmers transformers at LVD substations. The Company prioritizes which transformers to replace each year based on DGA testing results and infrared data. While the Company has identified the projects for the bridge period and the test year, the Company could re-prioritize and target different transformers if testing results indicated that reprioritization is warranted to reduce the probability of transformer failures across the system.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The projects in the LVD Substations Rehabilitation sub-program replace degrading and obsolete equipment with a high risk of causing service interruptions or reducing service quality, resolve unsafe substation conditions, and resolve conditions that could degrade substation reliability. Delaying replacement of this equipment is likely to lead to unplanned outages, and interrupting service to customers.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Rehabilitation sub-program?

A. The Company is projecting LVD Substations Rehabilitation capital expenditures of $31,000,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 25, column (k), and $31,328,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 25, column (l). The Company's historical actual spending in the LVD Substations Rehabilitation

sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 25.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The LVD Substations Rehabilitation sub-program is an important part of the Company's plan to address deteriorating assets and maintain reliability. The bridge period and test year spending amounts were determined based on the amount of investment needed to complete the projects identified.

By investing at the projected spending level in the bridge period, the Company will be able to: (i) complete nine projects to replace Allis Chalmers substation transformers; (ii) complete 14 transformer progress payments; (iii) complete six projects to address working clearance code issues; and (iv) complete nine projects to replace equipment.

By investing at the projected spending level in the test year, the Company will be able to: (i) complete three projects to replace Allis Chalmers substation transformers; (ii) complete 14 transformer progress payments; (iii) complete two projects to address working clearance code issues; (iv) complete four projects to replace equipment; and (v) complete 395 recloser replacements.

Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. This level of spending is adequate to meet the sub-program goals and regulatory deadlines while remaining agile to address imminent failure concerns.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as shown in Figure 45 below. Bridge period and test year investment is commensurate with the levels achieved by the Company in 2025; however, total test year investment is higher due to the addition of recloser replacements.

FIGURE 45
LVD SUBSTATIONS REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Allis Chalmers substation transformer replacements	$16,375,000	9	$15,371,000	3
Equipment replacement and regulatory	$14,625,000	16	$4,809,000	6
Recloser replacements	$0	0	$11,148,000	395
Total	**$31,000,000**	**25**	**$31,328,000**	**404**

Q. How are the projected LVD Substations Rehabilitation expenditures aligned with the Reliability Roadmap?

A. As previously discussed in the section of my testimony on the LVD Substations Reliability sub-program, the Reliability Roadmap includes an assessment of LVD substation asset health and presents an increased investment plan to address assets at risk. The Company is increasing its investment in both LVD substations-related sub-programs in response to the plan laid out in the Reliability Roadmap.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No, the average unit cost does not accurately reflect the expected spending due to specific work scopes needed for each project, transformer progress payments, and the variance in costs depending on the individual project scope. The nature of transformer progress payments is such that spending may occur in a given year with no corresponding unit to divide by, meaning it would be mathematically difficult to even calculate a unit cost to begin with. That said, with Allis Chalmers transformer replacements, the Company is getting closer to the end of the overall initiative and is reaching the point where more difficult and expensive projects remain. Average unit cost does generally reflect the expected spending per project for the recloser replacement investment category.

f) <u>Metro Reliability</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the Metro Reliability sub-program.

A. The Metro Reliability sub-program ensures the long-term safe and reliable operation of the Company's Metro systems with investments to install and upgrade the civil and electrical assets that distribute electricity in those downtown cores. Metro Reliability investments fall into three categories:

(i) obsolete or needed civil assets;

(ii) obsolete or needed electrical assets; and

(iii) dead fronting equipment.

Q. How does the Company address projects that require modified civil infrastructure?

A. For projects that require new or modified civil infrastructure, the Company releases the scope to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides several options for possible routes and estimated construction costs for those options. The Company's metro engineering planner reviews the feasibility study with operations representatives to determine ease of construction and impact to future electric operations. The metro engineering planner notifies the civil engineering firm, who will prepare a design based on the selected option. The metro engineering planner will prepare an electrical design, cable pulling schedule, and electrical bill of materials. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the ROW from the municipality, including a detailed traffic control plan.

Q. How are Metro Reliability expenditures aligned with the Reliability Roadmap?

A. Planned Metro Reliability expenditures in this case are aligned with those presented in the Reliability Roadmap, and projects are also identified based on the process outlined in the Reliability Roadmap, whereby Metro planning and design engineers assess multiple components of each vault, which produces a vault health score.

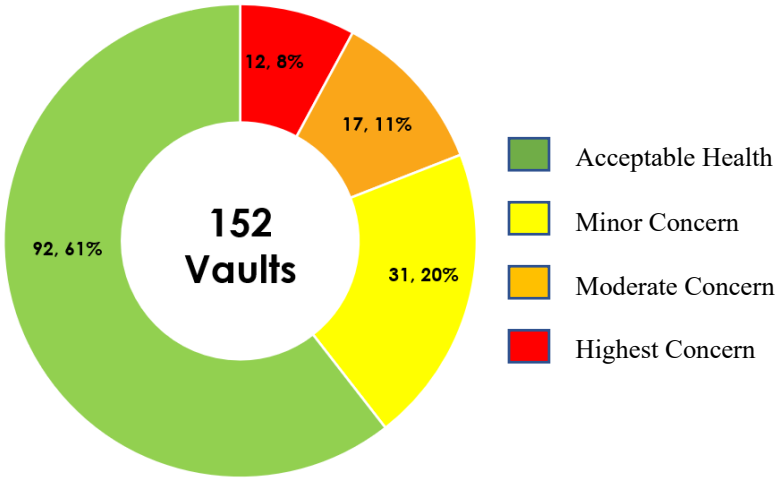
The Company reviews Metro Reliability projects during an annual planning cycle. While the Company continuously monitors the reliability of the Metro system, this annual review helps determine which line segments and components need to be addressed each year, as some projects may be large enough to span multiple years. Additionally, the Company determines which remediation strategy to use. Due to the lengthy customer interruptions that a Metro outage can cause, these projects are proactive to prevent an outage

from occurring and not due to a previous interruption. Inputs the Company uses in its Metro reliability assessment include:

- Metro condition is assessed based on safety and ability to operate existing equipment;
- Projects are prioritized based on reliability benefits to each customer category, with highest priority for critical customers, followed by large residential customers and then other commercial and residential customers; and
- When the Company receives external requests, particularly for Metro New Business and Metro Asset Relocations, the Company may also perform Metro Reliability work at the same time to gain efficiencies.

The Company's current Metro asset health results are summarized in Figure 46 below.

FIGURE 46
SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS, Q4 2025



Q. How are high-rise vaults evaluated for potential reliability upgrades?

A. As discussed earlier in my testimony, LVD Metro Planning & Design also manages vaults in high-rise buildings in other parts of the state outside of downtown cores. Similar to vault health assessments, high-rise vaults are also evaluated based on criteria to calculate a high-rise health score. These criteria evaluate the safety and operability of the high-rise vault. High rises typically contain both Metro and LVD assets, and successful reliability

upgrades must be closely coordinated. While the Company is evaluating these high-rise vaults, it is not proposing any projects in the instant case.

Q. What types of work does the Company complete as part of obsolete electrical asset replacement projects?

A. The Company replaces functionally obsolete equipment, including:

(i) Deteriorated SF6 insulated switches with new SF6 insulated switches;

(ii) PCB oil-insulated voltage transformers with non-PCB transformers and dead front busing well inserts; and

(iii) Impregnated Paper Lead Covered and Varnished Cambric Lead Covered cable with crosslinked tree retardant polymer insulated cables.

Q. What types of work does the Company complete as part of dead fronting equipment?

A. Dead fronting equipment enhances worker safety by eliminating exposed energized components in Metro assets. The Company does this by replacing:

(i) Live-front, vault-style transformers and fusing with molded vacuum interrupters;

(ii) Encapsulated transformer bushings (fuses and elbow type) and live secondary buss with guarded load centers;

(iii) High rise live-front transformers and switches; and

(iv) Obsolete primary and secondary cables in vaults.

Q. What benefits will customers realize through the Company completing work, in the Metro Reliability sub-program?

A. Metro Reliability investments minimize potential adverse impacts on customers by improving overall reliability and operational safety. Civil projects share the benefits with the corresponding electrical project. Benefits are fully realized when the electrical portion is completed. Furthermore, investments in the Metro Reliability sub-program can reduce overall cost associated with emergent response in the Metro Demand Failures sub-program.

Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. These benefits for the bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-156 (KKL-3), page 10, and A-157 (KKL-4), page 7. Types of benefits identified in the exhibits, and summarized in Figure 47, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience in a year once the project is complete; and
- Worker Safety – create safer work conditions within metro vaults.

FIGURE 47
METRO RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	139,607	2,710
Worker Safety projects	3	2

Q. What is an example of a recently completed Metro Reliability project that created safer work conditions?

A. The Company recently completed a vault dead fronting project at the Bell Vault in Jackson. The vault previously had obsolete electrical equipment and presented a worker safety concern to energized and exposed electrical components while working within the vault. In addition, parts of the vault roof and walls required some concrete rehabilitation repairs. The electrical equipment was updated to mitigate all exposed electrical component hazards, and the civil repairs were completed and sealed with a concrete sealant, extending the life of the structure. Secondly, the vault was prepped for a primary voltage conversion that will occur in the next few years.

FIGURE 48
VAULT BEFORE AND AFTER RELIABILITY PROJECT - BEFORE



FIGURE 49
VAULT BEFORE AND AFTER RELIABILITY PROJECT - AFTER



Q. Please describe the types of risks encountered as part of this sub-program.

A. Risks that may be encountered during construction of Metro Reliability projects that can impact cost include:

- Encountering crushed conduit while attempting to replace cable. Conduit can be crushed as a result of heavy loaded objects above the ground or the fiberglass becoming brittle as a result of exposure to soil conditions;

- Increased costs associated with temporary transformation and items required to temporarily connect customers to this equipment. The use of a mobile vault may be needed to allow for safe maintenance or construction work on de-energized equipment; and

- Potential fluctuation in contractor costs. Contractor costs can fluctuate between projects based on the bids received. This is based on the amount of work that the contractor already has secured and the cost for the contractor to add this to their work plan (additional or mobilizing resources).

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Reliability sub-program.

A. The Company has identified projects for the bridge period, which are listed in Exhibit A-156 (KKL-3), page 10, and for the test year, which are listed in Exhibit A-157 (KKL-4), page 7. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The identified projects will benefit customers by addressing historical outages and ensuring the long-term safe and reliable operation of the LVD metro system. These benefits will be realized through the replacement of degrading equipment before further service interruptions occur, and by updating Metro vaults and manholes to modern design standards and electrical clearances to improve worker safety.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Reliability sub-program?

A. The Company is projecting Metro Reliability capital expenditures of $5,330,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 23, column (k), and $4,131,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 23, column (l). These values are consistent with the five-year average spend in this sub-program of $5,033,000 as shown in Exhibit A-87 (EMD-3), line 23, column (h). The Company's historical actual spending in

the Metro Reliability sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 23.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The bridge period and test year spending amounts were determined based on the amount of investment needed to complete the projects identified. The Company has been experiencing an increase in both incidents and customer-outage-minutes in the Metro systems in recent years, as shown in Figure 50. By investing at the requested spending levels, the Company has been able to repair or replace Metro assets that have been identified as contributing to outages to downtown customers.

FIGURE 50
METRO SYSTEMS ANNUAL OUTAGE HISTORY

	2021	2022	2023	2024	2025
Number of incidents	26	17	26	31	36
Total customer-outage-minutes	550,414	341,144	344,979	903,757	289,417

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 51 below.

FIGURE 51
METRO RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Obsolete or Needed Civil Assets	$2,430,000	2	$2,800,000	2
Obsolete or Needed Electrical Assets	$1,900,000	4	$506,000	2
Dead-Fronting Equipment	$1,000,000	3	$825,000	2
Total	**$5,330,000**	**9**	**$4,131,000**	**6**

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program has been consistent year to year with an average annual spending of $5,033,000, as shown in Exhibit A-87 (EMD-3), line 23. 2024 had a higher-than-average annual spending primarily due to the one-time purchase of two mobile vaults.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. Average unit cost is not a good measure to predict the cost of an individual project in this sub-program. There is a wide variance of scale and scope among the work required ranging from $250,000 to dead front a small vault to over $1,000,000 for a civil replacement project.

g) <u>Metro Rehabilitation</u>

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the Metro Rehabilitation sub-program.

A. The Metro Rehabilitation sub-program addresses assets on the Company's Metro systems that have been identified as being at a high risk of imminent failure, such that replacement is justified based on potential risks to public, employee, or contractor safety, or to maintain the reliability of the Metro systems. The Metro Rehabilitation sub-program consists of two investment categories: crushed duct replacements and vault or manhole rehabilitation.

Q. Please explain crushed duct replacements.

A. When an existing duct bank has been crushed or is deteriorated, it is replaced with a new concrete-encased duct bank. New cable must also be run through the new duct bank to replace the damaged cable.

Q. Please explain vault or manhole rehabilitation.

A. Vaults or manholes require replacement of the entire structure—or portions of the structure, such as an existing roof—that is damaged or deteriorated. Damaged or deteriorated subsurface structures create safety hazards to the public passing over them and employees entering the structure.

Q. How are the projected Metro Rehabilitation expenditures aligned with the Reliability Roadmap?

A. Similar to Metro Reliability, planned Metro Rehabilitation activities are tied to addressing asset health concerns in Metro assets, and expenditures in this case are aligned with those presented in the Reliability Roadmap. Projects are identified based on the process outlined in the Reliability Roadmap as well.

Q. Did the Company consider any alternative approaches to project selection that could help achieve the Reliability Roadmap objectives?

A. Yes. Alternatives are considered for each project in the Metro Rehabilitation sub-program; however, viable options are often limited due to the need to maintain service in the dense downtown districts. One alternative often evaluated is whether a given vault can be eliminated and replaced with an at-grade transformer installation. This alternative is wholly dependent upon suitable space to install the at-grade facilities, which often is not available in the downtown areas. Alternative locations for the new facilities and rerouting of electrical cables through already existing civil infrastructure are also considered. Each project is selected based upon its effectiveness at solving the identified problem, the cost of the project, and the relative benefits.

Q. What benefits will customers realize through the Company completing work in the Metro Rehabilitation sub-program?

A. Upgrading and replacing degraded components in the Metro system allows the Company to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts customers including courthouses, jails, municipal offices, police, and fire departments, as well as many businesses and residents. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. Additionally, a Metro system in good condition allows employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single sourced as the Company isolates manholes and vaults for repair. These benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-156 (KKL-3), page 11, and A-157 (KKL-4), page 8. Civil projects share benefits with the corresponding electrical project; benefits are fully realized when the electrical portion is completed. Types of benefits identified on the exhibits and summarized in Figure 52 include customer-outage-minutes avoided; as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience in a year once the project is completed.

FIGURE 52
METRO REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	62,979	9,011

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Rehabilitation sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-156 (KKL-3), page 11, and for the test year, listed in Exhibit A-157 (KKL-4), page 8. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The Metro Rehabilitation sub-program is a key component of the Company's plan to improve overall reliability. This sub-program addresses those components of the Metro asset base that are most vulnerable to failure and corresponding interruptions to customers. By investing at the requested spending level, the Company will be able to repair or replace Metro assets identified as being at a high risk of imminent failure.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Rehabilitation sub-program?

A. The Company is projecting Metro Rehabilitation capital expenditures of $2,953,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 27, column (k), and $5,495,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 27, column (l). The Company's historical actual spending in the Metro Rehabilitation sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 27.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected bridge period and test year spending amount was determined based on the amount of investment needed to complete the projects identified. The Company is maintaining spending levels for the bridge period and test year to continue to address rehabilitation projects.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 53.

FIGURE 53
METRO REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Crushed duct replacements	--	0	$2,995,000	1
Vault or manhole rehabilitation	$2,953,000	8	$2,500,000	2
Total	**$2,953,000**	**8**	**$5,495,000**	**3**

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program. There is a wide variance among work required, ranging from $200,000 for small vault projects to as high as $1,800,000 for crushed duct and vault rehabilitation projects.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program may vary from year to year, due to size, scope, complexity, timing, and delays to some of the projects. Spending was noticeably higher in 2023, with just over $7,000,000 in investment. This was driven by three large civil projects in Jackson, Flint, and Saginaw.

h) System Protection

Q. What is the purpose of the HVD protective system?

A. The distribution system experiences electrical faults such as wire downs, lightning strikes, and failed equipment. When this happens, the purpose of a protective system is to de-energize as quickly as possible the minimum amount of the electric network that has experienced a fault, to isolate the fault, and mitigate damage to other equipment.

Q. Do protective systems experience failures?

A. Yes, protection systems have two modes of failure. The first is an incorrect operation, which is when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases can lead to cascading outages that result in widespread blackouts. Protection system failures have played a part in many of the largest blackouts in history, including a protective system failure on November 9, 1965, that caused the "Northeast Blackout of 1965," interrupting service to 30 million people; and a protective system failure on February 26, 2008, in Florida, resulting in 4,300 MW of generation going off-line, and a loss of 3,560 MW of customer load, and a fine to Florida Power and Light by the Federal Energy Regulatory Commission of $25 million. Protection system failures also contributed to the largest United States blackout in history on August 14, 2003. These failures resulted in the creation of dozens of new reliability

standards by the North American Electric Reliability Corporation related to the operation and maintenance of protective systems.

The second failure mode is when a protection system does not correctly deenergize an electrical fault. Failure of a protection system to de-energize a fault can lead to more customers interrupted than are necessary, equipment damage as lines and/or transformers burn up, environmental hazards due to ruptured transformers, and public safety hazards due to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical faults.

Q. Do failures detrimentally impact customers?

A. Yes. Since failure of a protection system during a fault can result in extensive damage to the electric network, it can take much longer to restore service to customers while additional equipment is repaired or replaced. Due to these risks, protection systems are a critical function of the electric network since they backstop against extensive outages and public safety hazards when other components of the electric network fail. When protective systems fail, this can result in the outage impacting a larger area than is necessary to isolate the fault. This makes it more difficult to locate the problem on the electric network and extends the time needed for restoration.

Q. What is the present state of the Company's HVD protective system?

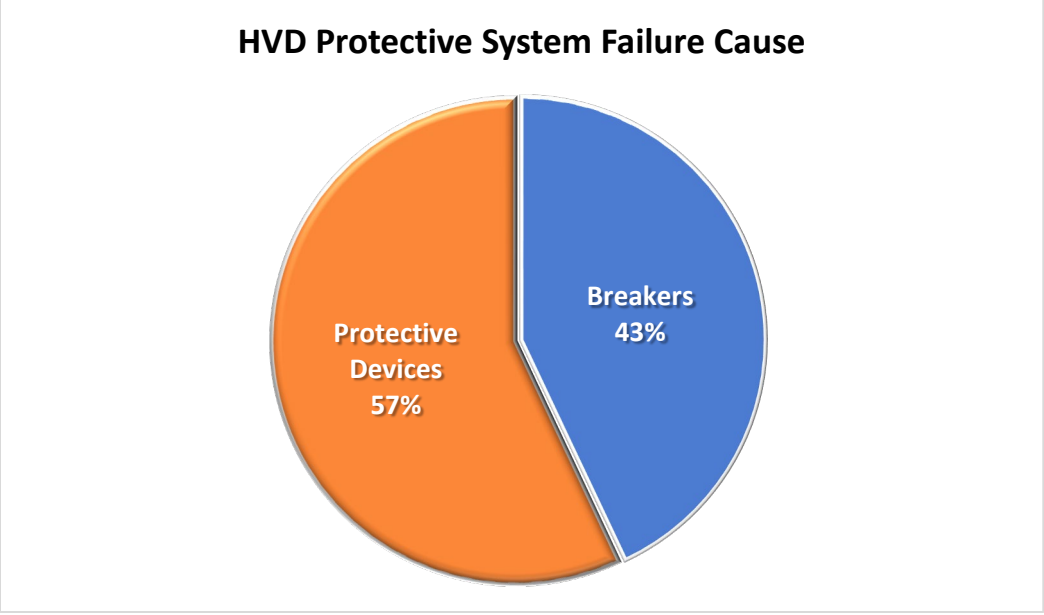
A. The Company has determined design life for protective relays based on vendor recommendations, industry best practices as documented by the Institute of Electrical and Electronics Engineers ("IEEE") Power System Relaying Committee, and Company experience with failure of specific relay types. Approximately 16% of the protective relay population is older than the designated design life; this increases to 35% for the population

of electromechanical ("EM") relays. As EM relays age, they are more frequently out of settings tolerance, which can cause interrupting devices (like circuit breakers, circuit switchers, etc.) to open when they do not need to, or not open when they should, leading to interruptions and possible damage to equipment. More frequent field testing and calibration is required to ensure proper performance.

Q. How will replacing EM relays with digital relays support customer reliability?

A. Digital relays do not lose setting tolerance like EM relays and require significantly less maintenance. Historical EM relays require maintenance twice as often to keep within their setting tolerance. Replacing historical EM relays with digital relays not only reduces the risk of failure, but also lowers O&M expenses associated with relay testing. Over the past three years, relays contributed to approximately 57% of the failures of an HVD protective system to clear a fault and restore un-faulted HVD equipment correctly (see Figure 54).

FIGURE 54
HVD PROTECTIVE SYSTEM FAILURE TO CLEAR AND RESTORE BY CAUSE. 2022-2024



Q. Why is the Company requesting approval for these projects in this proceeding?

A. The relays replaced under this program are obsolete and, in most cases, no longer available, so quick like-for-like replacement is not an option. Replacement requires building new relay panels, which take several months to design, build, and install. Proactively replacing these panels reduces the risk of outages when a relay failure occurs. Further, projections show an increasingly large number of obsolete relays reaching end-of-life (with an increased risk of failing) over the next 10 years as described in the Reliability Roadmap. A consistent level of investment to replace a smaller number of relays each year will avoid a mass failure of relays in the future that would strain resources to replace all at once.

Q. What projects, activities, and other types of work will be funded by expenditures in the System Protection sub-program, to help achieve these longer-term reliability objectives?

A. The System Protection sub-program replaces obsolete relays with new digital devices that have fault monitoring capabilities to improve reliability and offset future O&M costs. This sub-program targets relays that are reaching end of life.

Q. What benefits will customers realize through the Company completing work in the System Protection sub-program?

A. As noted above and discussed in the Reliability Roadmap, protection systems are critical to minimizing damage and protecting public safety as the final backstop when other components of the electric network fail. Replacing end-of-life HVD relays before they fail helps mitigate the expanded outage risk to customers and the hazard to the public. The projected expenditures provide for the level of investment necessary in the System

Protection sub-program to address obsolete, poor performing relays to ensure proper operability of the HVD network and minimize the risk of outages to customers.

Q. Please provide additional information on the benefits to safety and how the investment will benefit customers.

A. If a protection system fails to de-energize a fault, it can result in safety hazards. For example, a failed protection system can cause a conductor to remain energized on the ground, posing an electrocution risk. A fault that is not cleared correctly by the protection system could also cause a fire, and/or an explosion of electric equipment like transformers. An extended fault can also result in an environmental spill of oil. Investment in the HVD protective system is paramount to ensuring the public is kept safe from the hazards of the HVD electrical system.

Q. How does the System Protection sub-program impact reliability?

A. While safety is a key priority of the HVD protective system, the protective system also directly impacts reliability. As noted above, there are two failure modes for protective systems. When protective systems fail by operating when they should not, this can cause unnecessary outages to customers due to tripping portions of the electric system that are not experiencing a fault. When protective systems fail by not operating when they should, this creates a need to interrupt more of the electric system than is necessary to clear the fault and can interrupt more customers than necessary. The latter scenario can also cause additional damage, such as transformer fires or damaging line conductors due to the extended fault clearing times, and takes longer to repair and restore customers due to the additional damage and larger area of outage.

The System Protection sub-program also plays a role in reducing CAIDI, which in turn reduces SAIDI. New digital relays contain oscillographic recording functions that allow for evaluation of system conditions in real time, allowing engineers to remotely interrogate the system to locate faults more quickly and with more precision. This allows repair crews to find the problem and address it more quickly, restoring customers faster, which reduces CAIDI.

Q. Are there any other benefits to replacing EM relays with digital ones?

A. Experience has shown that digital relays can be tested once every five years instead of once every four years for EM relays. The time spent to test and calibrate digital relays is 50% less than a comparable EM relay. One HVD relay project typically replaces six EM relays with two new digital relays. Considering these reductions, the Company estimates that a modern digital relay package requires 87% less O&M expense on average to maintain than a comparable EM unit.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, in the System Protection sub-program?

A. The Company is projecting System Protection capital expenditures of $5,939,000 in the bridge period and $4,672,000 in the test year, as shown in Figure 55 below.

FIGURE 55
SYSTEM PROTECTION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Category	Bridge Period Capital	Bridge Period Units	Test Year Capital	Test Year Units	Benefit
Relay Replacements	$5,939,000	48	$4,672,000	28	Safety, Reliability
Total	**$5,939,000**	**48**	**$4,672,000**	**28**	

Q. What is the basis for the Company's projected test year spending level in the System Protection sub-program?

A. The Company's projected System Protection investment in the test year is closely aligned with the five-year average, which is shown in Exhibit A-87 (EMD-3), line 21. Based on the relay asset health model, spending at the five-year average level will reduce the quantity of installed relays beyond their design life to zero in 2029 and sustain that level going forward from that point.

This level of investment will support 28 relay units at eight sites in the test year. The specific costs for the test year projects were determined using unit costs based on past work order costs for replacement of like equipment, and further refined taking into consideration the complexity of the specific relay schemes as well as the need for replacement of control enclosures due to NESC working space requirements. The average unit costs for the test year are expected to be higher due to one project requiring a new control enclosure due to NESC working space requirements.

Q. Please list any projects that make up the requested spending level in the System Protection sub-program for the bridge period and test year.

A. Projects for the System Protection sub-program are identified in Exhibit A-156 (KKL-3), page 12, and Exhibit A-157 (KKL-4), page 9.

Q. What has been the historical actual spending in the System Protection sub-program for the past five years?

A. The historical actual costs for the System Protection sub-program are shown in Figure 56 below.

FIGURE 56
SYSTEM PROTECTION HISTORIC SPENDING

2021	2022	2023	2024	2025	5-Year Average
$2,620,111	$4,504,000	$4,386,998	$4,848,000	$5,244,000	$4,320,000

Q. Please explain the year-over-year variation in spending in this sub-program.

A. In 2021, the effects of the pandemic resulted in a decrease in the overall spending in this sub-program compared to earlier years as availability of construction resources and materials was challenged, and spending increased after that point to return to more normal levels. Additionally, beyond 2021, spending has ramped up to mitigate the risk described above of relays in service beyond their design life as identified in the relay asset health model.

Q. What are the historical unit costs for the System Protection sub-program?

A. Historical unit costs are provided in Figure 57 below; note that some projects span multiple years:

FIGURE 57
SYSTEM PROTECTION UNIT COSTS

Investment Categories	2021	2022	2023	2024	2025
Locations	3	10	10	6	14
Total Relay Replacements	13	41	36	17	17
Cost per Location	$873,366	$409,455	$409,455	$808,000	$374,571
Cost per Relay Replacement	$201,546	$109,854	$121,861	$285,176	$308,470
5-Year Average Cost per Relay Replacement	**$115,061**				

Q. Please explain any variation in unit costs over time.

A. Costs per location can easily vary because each project at each given location can involve a different number of relay replacements. Additionally, some projects carry over from one year to the next; in these cases, dollars are spent throughout the project, but the unit is only counted once it is complete. This makes unit costs less consistent from year to year. For instance, the 2021 unit cost was relatively high because several units that began in 2021 did not complete until 2022, while most of the cost of those projects were incurred in 2021. The 2022 unit cost was relatively low because of the high unit count of projects carried over from 2020, where most of the costs for those projects were incurred in 2020. Similarly, the 2025 unit cost was high because approximately 42 units started in 2025 will be completed and counted in 2026. Averaging the unit cost over the life of each project rather than by budget year brings a more consistent unit cost average of approximately $223,000 per relay replacement. The average unit cost is expected to decrease significantly when the carryover of approximately 42 units is counted in 2026.

2. CAPACITY

a) HVD Lines and Substations Capacity

Q. What is the purpose of the HVD Lines and Substations Capacity sub-program?

A. The overall purpose of the Capacity Program is to ensure that the system can serve peak demand load, as discussed by Company witness Duke in her direct testimony. The HVD Lines and Substations Capacity sub-program is specifically designed to:

- Ensure capacity needs on the HVD system in accordance with HVD planning criteria;
- Accommodate new interconnections to the HVD System;
- Improve functionality through standards, upgrades to protection, and operability of the system;

- Coordinate with transmission infrastructure additions; and
- Support ROW acquisition projects to support HVD Lines and HVD Substation projects in this sub-program as well as ROW acquisition needed to bring existing HVD Line and HVD Substation ROWs up to present standards.

Q. To what extent are HVD Lines and Substations Capacity sub-program investments "planned"?

A. Each Capacity sub-program consists primarily of investments that are proactive, in that they do not respond to an emergency. However, there are circumstances where projects may need to be pulled ahead or inserted into the plan, for example to avoid an overload caused by unexpected load growth, an unexpected request to coordinate with a Transmission project, or third-party generator interconnection requests.

Q. How does the HVD Lines and Substations Capacity sub-program align with the Reliability Roadmap?

A. This sub-program is aligned with the "HVD Load Growth and Interconnection" component of the Reliability Roadmap. Investments in this sub-program support the Company's goals of ensuring that the HVD system can serve electric peak demand, accommodate new interconnections, and ensure current standards to support improved functionality of the system.

Q. What benefits will customers realize through the Company completing work in the HVD Lines and Substations Capacity sub-program?

A. Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. This sub-program ensures that the HVD system has the capacity to accommodate potential changes to the load profiles needed for new and changing technologies such as electrical vehicles and other potential

electric growth in the future due to emerging technologies. Although this sub-program is not specifically designed to address system deterioration, investments in this sub-program improve system reliability and safety, and prevent future overloads, which can trigger dangerous wire downs and equipment failures due to exceedance of equipment interrupting capability.

Q. What investment categories are included in the HVD Lines and Substations Capacity sub-program?

A. The investment categories are:

- Load Carrying Capabilities and Voltage Support
- New Interconnections
- Improved Functionality
- Coordination with Transmission
- ROW Procurement

However, New Interconnections projects are typically fully reimbursed by third parties, so the Company does not typically request rate recovery for projects in that category.

Q. What projects are funded by the Load Carrying Capabilities and Voltage Support investment category?

A. The Load Carrying Capabilities and Voltage Support investment category contains projects that eliminate unacceptably low voltage, loadings above line and equipment ratings, and available short circuit above equipment interrupting capability. These capacity projects must be completed based on projected loading in power flow models to serve customers and maintain the safety and overall reliability of the grid. The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in

power flow and voltages resulting from single outages for present and future versions of the HVD system. The HVD system model is updated annually, following summer peak loading and into the first quarter of the following year. The studies are performed in the second quarter each year, and projects are then developed to address identified projected issues before the issue occurs in subsequent years. SCADA information is also used to project future load on the HVD system. Through this process, HVD facilities are identified that would violate the HVD Planning criteria due to line or equipment overload, or due to unacceptably low voltage during base (normal) conditions at system peak load or during single (N-1 equipment out of service) outage conditions at 80% of system peak load. Outage conditions studied include single line, single transformer, single bus, and single generator outages. Also identified are interrupting devices where the available short circuit is projected to exceed interrupting capability. The Company's plans to fix projected criteria violations are tested in the models to ensure they fulfill their designed purpose.

Q. How are projections of peak load developed?

A. Each year, after summer peak conditions, the Company revises its load forecast to reflect the most recent experience with customer peak usage. The load forecast is done at the system and circuit levels and represents the simultaneous usage of all downstream customers.

Q. How does the Company project loading on individual elements of the electric system?

A. For HVD elements, the Company's planning engineers allocate the system load to individual substation loads using SCADA data. The Company's planning engineers then use power flow modeling to identify loading on each element of the electric system. The power flow model simulates how power flows on the electric system, based on the

fundamental laws of electricity. These models can identify loading on each element, compare it with the capacity of that element, and provide the Company's Planning Engineers with those instances where capacity is insufficient to meet projected loading.

Q. How does the Company determine the capacity of individual elements of the electric system?

A. The Company's design engineers determine the capacity of elements based on manufacturer or industry resource standards (*e.g.* IEEE standards). Multiple data sets and software programs are used to assist in determining capacity of each element.

Q. How are the Company's equipment ratings developed?

A. Equipment ratings — essentially the capability of a piece of equipment — are developed to ensure equipment is capable of handling peak hour loading over multiple hours, not just a single peak hour. In other words, equipment ratings are based on an ability to handle load at a particularly sustained loading level for a period. The Company bases its equipment ratings on manufacturer or industry resource standards (*e.g.* IEEE standards).

Q. Can you provide an example of a Load Carrying Capabilities and Voltage Support Project?

A. Yes. A recent example is from the Flint area, where forecasted loading was projected to exceed the capacity of the 46 kV Linden Line for certain system contingencies that removed the source from one end of line and forced the other end to serve the entire load on the line. The only cost-effective solution to this overload was to increase the capacity of the line by rebuilding 3.91 miles of the line with a higher capacity conductor.

Q. What projects are funded through the New Interconnections investment category?

A. The New Interconnections category contains new interconnections to other utilities and generation facilities that must be completed as requested by the interconnecting party. Costs to interconnect other utilities and generation facilities to the Company's HVD system are typically reimbursed by the other utilities or generators being interconnected.

Q. Has the Company made any changes to the New Interconnections investment category?

A. Yes. Prior to 2024, the New Interconnections investment category also contained HVD interconnections to LVD substations. For example, a new 46 kV line might be needed to connect a new LVD substation to the existing HVD system. Starting in 2024, these HVD facilities needed to connect an LVD substation to the HVD system are included with the LVD substation project in the applicable LVD substation sub-programs. This change was made to better align the planning for scope, schedule, and budget for all portions of a project to the overall initiating need. In other words, if an LVD substation project is planned, then the full scope for that LVD substation project, including any needed HVD lines, will now all be contained within the LVD substation project itself.

Q. What projects are funded through the Improved Functionality investment category?

A. The Improved Functionality category contains projects that are completed to meet changes in standards and upgrades to protective schemes for Grid Operability/Reliability on a planned basis over a period. An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period. It is often coordinated with other major projects as they occur at the same location. Configuration changes to improve operability are made at the request of the Grid Management group or through

coordination with other major projects as they occur at the same location. As discussed earlier in my direct testimony for the HVD Lines Reliability sub-program, the Improved Functionality investment category includes line sensors through the end of the 2024 calendar year, after which they were shifted to HVD Lines Reliability.

Q. What projects are funded through the Coordination with Transmission investment category?

A. The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require HVD upgrades to be completed as well. These are completed as needed over time in conjunction with the transmission owner.

Q. What projects are funded through the ROW Procurement investment category?

A. When existing easements are insufficient, ROW Procurement projects are necessary to procure land or land rights for HVD lines and substation sites across the HVD Capacity capital sub-program prior to construction and can require significant lead time. Through the process of monitoring and studying load profiles and planning for future infrastructure rebuilds or replacements, properties are sought and procured to build electric infrastructure at the right point in time needed to serve customers or meet infrastructure rebuild or replacement project timelines.

Q. Has the Company made changes to the ROW Procurement category within this sub-program for calendar year 2024 and beyond?

A. Prior to 2024, the ROW Procurement category within this sub-program contained ROW procurement for all HVD ROW needs, including ROW needed for projects in other sub-programs. For example, ROW needed for a new 46 kV line, to connect a new LVD

Substation, or for an HVD line or substation rebuild would have been included in HVD Lines and Substations Capacity. Starting in 2024, these ROW acquisitions for projects in other sub-programs are included within those other respective sub-programs. This change was made to better align the planning for scope, schedule, and budget for all portions of a project to the overall initiating need.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery in the HVD Lines and Substations Capacity sub-program?

A. The Company is projecting in the bridge period HVD Lines and Substations Capacity capital expenditures of $41,904,000, and test year expenditures of $34,956,000, as shown in Exhibit A-87 (EMD-3), line 32. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 58 below.

FIGURE 58
HVD LINES AND SUBSTATIONS CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	# Units	Test Year Capital	# Units	Benefits*
Load carrying capabilities and voltage support	$10,196,000	3	$2.152,000	3	Avoid overload, mitigate inadequate clearance, offset transmission costs, 1,466,014 customer minutes
Improved functionality	$14,619,000	25	$15,559,000	14	Regulatory compliance, mitigate inadequate clearance, new standards, safety, grid operability/reliability,429,970 customer minutes
Coordination with Transmission	$8,732,000	14	$16,368,000	7	Contractual requirement to coordinate with Transmission projects
ROW procurement	$8,357,000	8	$877,000	3	Needed to support ROW needs for many projects
Total	**$41,904,000**		**$34,956,000**		

*NOTE: All customer minutes are summarized by project in Exhibits A-156 (KKL-3) and A-157 (KKL-4).

Q. What benefits will customers realize through the Company completing work in the HVD Lines and Substations Capacity sub-program?

A. Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. This sub-program ensures that the HVD system has the capacity to accommodate potential changes to the load profiles needed for new and changing technologies such as electrical vehicles and other potential electric growth in the future due to emerging technologies. Although this sub-program is not specifically designed to address system deterioration, investments in this sub-program improve system reliability and safety, and prevent future overloads, which can trigger

dangerous wire downs and equipment failures due to exceedance of equipment interrupting capability.

Q. What is the basis for the requested spending level for the HVD Lines and Substations Capacity sub-program in this filing?

A. The requested spending levels for the bridge period and test year are based on the total of all costs in the Company's workplan. The cost projections in this sub-program were developed using derived costs, where available, that have been based on historical actuals experienced for similar projects. In many cases, the costs are also further refined with support from the Company's design and project management departments, taking into consideration the specifics of each project such as the location, expected site conditions, and up-to-date material and labor costs. The spending amounts for the bridge period and test year are determined by the combined costs of individual projects and will allow the Company to complete the projects listed, and deliver the benefits summarized above. The capital projects planned for the bridge period and the test year, as well as their investment categories, locations, and benefits to reliability are shown in Exhibits A-156 (KKL-3), page 13, and A-157 (KKL-4), page 10.

Q. What has been the historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five years?

A. The Company's historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five years is shown in Figure 59 below.

FIGURE 59
HVD SYSTEM CAPACITY HISTORICAL SPENDING

2021	2022	2023	2024	2025	5-Year Average
$17,365,000	$29,292,000,	$25,805,000	$27,163,000	$20,006,000	$23,926,000

Q. The requested bridge period and test year spending amounts are higher than historical average. Are there projects in the bridge period and test year that are driving this increase?

A. Yes. The spending in both the bridge period and the test year is higher than the historical average due to the increased amount of work needed in the sub-program, with several large projects beyond typical historical levels. In the bridge period, one such project is the Linden 46 kV line rebuild, needed to address a projected overload on this line. This project is listed in Exhibit A-156 (KKL-3), page 13, line 43. The bridge period also includes the Saranac 46 kV line rebuild, needed to address a projected overload on this line as well as mitigate inadequate clearance between the 46 kV conductors and the LVD primary underbuild. This project is listed in Exhibit A-156 (KKL-3), page 13, line 42.

Other large projects needed in the test year are the projects at Santiago, Seven Mile, and Cottage Grove substations needed to coordinate with METC's Iosco – Karn 138 kV transmission line rebuild project (see Exhibit A-157 (KKL-4), page 10, line 4); and the Wealthy Street 138/46 kV Substation project needed to coordinate with METC's Snowy Transmission substation project (see Exhibit A-157 (KKL-4), page 10, line 7). The test period also includes the Delaney substation working space project, needed to bring facilities within the control enclosure up to present working space safety standards. This project also improves protection with the addition of 46 kV bus differential protection and new capacitor bank switchers with increased fault interrupting capability.

Q. Are there other factors that affect year-over-year variation in spending in this sub-program?

A. Projects in this sub-program have a variety of specific needs and in-service dates. Additionally, projects in this sub-program vary greatly depending on the required system upgrades, ranging from $10,000 or less for upgrading/replacing smaller equipment to several million dollars where an entire new substation or HVD line is needed, as can be seen in the project lists in Exhibits A-156 (KKL-3), page 13, and A-157 (KKL-4), page 10. Therefore, year-over-year variation in this program is driven by the timing needs of completing projects with such a great variance in scope and costs. Many of the projects are also driven either by a need to provide capacity before equipment overloads or by coordination with other parties, such as transmission owners, other utilities, and generation interconnections. Therefore, changes in load projections and changes in coordinating project schedules can drive variability in timing of spending. Combined with the very large costs of some projects, this can shift large amounts of spending from year to year.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No, the unit for this sub-program is projects, and the projects undertaken are specifically tailored and unique to only what must be performed, so the scope and cost of each project vary from project to project. There is a wide variance among work required, and a resulting wide range of individual project costs. For example, when looking at improved functionality projects in the test year, individual projects range from $35,000 up to $3,360,000.

b) LVD Substations Capacity

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Capacity sub-program.

A. The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of the Company's electric distribution LVD substations. The necessary capital expenditures include investments to install new substations or substation equipment, and to upgrade existing substations or substation equipment to ensure customer electric loads are served within the operating capacity of the installed substation equipment (*i.e.*, transformers, fuses, reclosers, voltage regulators, and switches). These investments include any necessary HVD line work and/or ROW procurement to support projects in this sub-program. The LVD Substations Capacity investments are divided into two categories: new substations and existing substation capacity increases.

Q. Did the Company consider any alternative approaches to project selection that could help achieve the Reliability Roadmap objectives?

A. Yes. Alternatives typically considered for each project include:

(i) transferring load to an adjacent and less loaded substation or line;

(ii) upgrading equipment or lines to provide the needed capacity;

(iii) building a new LVD substation to share the load capacity; and

(iv) connecting to a different HVD source.

Each project is selected based upon its effectiveness at solving the identified problem, the cost of the project, and the relative benefits.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Capacity sub-program?

A. LVD Substations Capacity investments are necessary for the overall operation and reliability of the electric distribution system by preventing future overloads and addressing existing overloads, which would eventually result in equipment failure and customer outages, while ensuring the Company has adequate capacity on the distribution system to serve customer load. The number of customers benefitting from each project in this sub-program in the bridge period are identified in the Benefit Type and Benefit columns of Exhibit A-156 (KKL-3), page 14, and for the test year, listed in Exhibit A-157 (KKL-4), page 11.

Q. How does the Company identify LVD Substations Capacity projects?

A. LVD Substations Capacity planning projects are developed to respond to peak load conditions. Monitoring with DSCADA and analysis are done to identify situations where a component of the LVD substation has experienced an overload of its rated capacity. These substation components are selected for a capacity upgrade project. If necessary, LVD substation capacity projects are prioritized to address the highest overloads in advance of lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact. When assessing loads, the Company prudently considers actual and known new business load additions.

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Capacity sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-156 (KKL-3), page 14, and for the test year, listed in Exhibit A-157 (KKL-4), page 11. Projected project

costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the benefits and county location of each project.

Q. Are NWAs considered in the LVD Substations Capacity sub-program?

A. The Company has been exploring the potential for considering NWAs as another alternative LVD substation capacity solution in recent years. Through recent pilots, the Company has refined its selection criteria for identifying potential LVD substations where NWAs can be considered, with criteria including the peak load reduction needed, the timeframe of the projected need, customer mix, and other factors. The Company has already begun considering NWAs, including solar and batteries, in some of its concept approvals for projects in this sub-program. However, as Company witness Duke discusses in her direct testimony, the Company is also still early in the process of exploring how NWAs can solve capacity and reliability issues on the system, and the Company is developing an expedited pilot to better understand NWA applications.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Capacity sub-program?

A. The Company is projecting LVD Substations Capacity capital expenditures of $18,885,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 33, column (k), and $22,399,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 33, column (l). The Company's historical actual spending in the LVD Substations Capacity sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 33.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected spending for the LVD Substations Capacity sub-program is based on the Company's identified capacity needs and planned projects to mitigate planning criteria violations. The bridge period spending amount was determined based on the amount of investment needed to complete the projects identified.

Project costs were determined based on the specific work scope for each project and historical costs from similar projects. This level of work and the associated spending are adequate to meet the sub-program objective to serve customer electric loads within the operating capacity of the installed substation equipment, thereby ensuring the long-term and reliable operation of the electric distribution LVD substations.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 60. Please note that the number of units in each column refers only to the number of units that will be field complete in the relevant period; as discussed below, many projects in this sub-program extend across multiple years, and these are not counted among the units listed here.

FIGURE 60
LVD SUBSTATIONS CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Projects	Test Year Capital	Test Year # of Projects
New substations	$10,019,000	1	$14,512,000	2
Existing substations projects	$8,866,000	5	$7,887,000	4
Total	**$18,885,000**	**6**	**$22,399,000**	**6**

Q. Are there any projects that span multiple years?

A. Yes, the Erastus, Mercury, Valentine, East Jackson, and Hickory projects listed for the bridge period in Exhibit A-156 (KKL-3), page 14, and for the test year listed in Exhibit A-157 (KKL-4), page 11, will span multiple years due to transformer progress payments and construction scheduling.

The Belvedere, Channel, Crandall, Garman Foster, N Avenue, Osterhout, Quicksilver, Glen Lake, Harrison, Newark, Nunica, and Ranger Lake projects listed for the bridge period in Exhibit A-156 (KKL-3), page 14, and for the test year listed in Exhibit A-157 (KKL-4), page 11 are planned for final completion in years beyond the test year, but investment will span multiple years due to transformer progress payments occurring in the bridge period and test year.

Because it can take more than two years to obtain a single transformer, the Company has placed transformer orders ahead of time to ensure they will be available in the planned project completion years. Making progress payments will allow the Company to ensure it has an adequate supply of transformers to complete planned 2027 through 2030 substation capacity increase projects.

Q. Please identify and provide a short description of the LVD Substation Capacity work associated with the new substation investment category.

A. Ten new substations are being planned. The Belvedere Substation (Allegan County) will be a new substation to resolve a Saugatuck Substation overload due to new residential and commercial developments. The new loads are projected to exceed the capability of the Saugatuck Substation Transformer #2 and Circuit #3 voltage regulators. The bridge period and test year spending includes substation property and HVD line ROW purchases and

substation transformer progress payments. Belvedere Substation is planned for 2029 completion.

The Channel Substation (Manistee County) will be a new substation to resolve a Manistee Substation overload due to a new 5 MVA load being proposed by a new customer. The new customer load added to the existing area load will exceed the capability of the Manistee Substation Circuit #1 voltage regulators. The bridge period and test year spending includes substation transformer progress payments. Channel Substation is planned for 2028 completion beyond the test year.

The Crandall Substation (Van Buren County) will be a new substation to resolve a Lawrence Substation overload and HVD system low voltage due to new customer loads and industrial park development. The new loads are projected to exceed the capability of the Lawrence Substation transformer and Circuit #1 voltage regulators and cause low voltage conditions on the HVD system serving Lawrence Substation. The bridge period and test year spending includes HVD line ROW purchases and substation transformer progress payments. Crandall Substation is planned for 2029 completion.

The Erastus Substation (Isabella County) will be a new substation to resolve a Clare Substation overload due to a new 3 MVA load proposed by a new customer. The new customer load added to the existing area load will exceed the capability of the Clare Substation transformer and voltage regulators. Erastus Substation will be completed in the 2027 bridge period.

The Garman Foster Substation (St Joseph County) will be a new substation to resolve a Mendon Substation and HVD system overload due to new customer loads and industrial park development. The new loads are projected to exceed the capability of the Mendon

Substation Transformer #2, Circuit #3 voltage regulators, and the HVD system serving Mendon Substation. The bridge period and test year spending includes HVD line ROW purchases and substation transformer progress payments. Garman Foster Substation is planned for 2029 completion.

The Mercury Substation (Calhoun County) will be a new substation to resolve a Renton Substation overload due to a new 4.5 MVA load being proposed by a new customer. The new customer load added to the existing area load will exceed the capability of the Renton Substation transformer, voltage regulators, and reclosers. Mercury Substation construction will start in the bridge period and will be completed in the 2027 test year.

The N Ave Substation (Kalamazoo County) will be a new substation to resolve an Atwater Substation overload due to new commercial loads. The new loads are projected to exceed the capability of the Atwater Substation Circuit #1 voltage regulators and the LVD feeder serving the area. The bridge period and test year spending includes substation transformer progress payments. N Ave Substation is planned for 2030 completion.

The Osterhout Substation (Kalamazoo County) will be a new substation to resolve Austin Substation and Portage Substation overloads due to new residential and commercial development. The new loads are projected to exceed the capability of the Austin Substation transformer and the Portage Substation Circuit #2 voltage regulators. The bridge period and test year spending includes substation transformer progress payments. Osterhout Substation is planned for 2030 completion.

The Quicksilver Substation (Kent County) will be a new substation to resolve Wealthy Substation overload due to several new developments with the City of Grand Rapids totaling 20 MVA. The new loads are projected to exceed the capability of the Wealthy Substation

Transformer #3, Transformer #4, and voltage regulators on several circuits. The bridge period spending includes substation transformer progress payments and the test year spending includes substation transformer progress payments and substation construction. Quicksilver Substation construction will start in the test year and will be completed beyond the test year in 2028.

The Valentine Substation (Kalamazoo County) will be a new substation to resolve Pavilion Substation overload due to new commercial and industrial development. The new loads are projected to exceed the capability of the Pavilion Substation transformer, Circuit #1 voltage regulators, and the LVD feeder serving the area. The bridge period spending includes substation transformer progress payments and substation construction and the test year spending includes substation construction. Valentine Substation construction will start in the bridge period and will be completed in the 2027 test year.

Because it can take more than two years to obtain a single transformer, the Company has placed transformer orders ahead of time to ensure they will be available in the planned project years. Making progress payments will allow the Company to ensure it has an adequate supply of transformers for the planned projects.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. The spending variation in the LVD Substations Capacity sub-program from 2021 to 2025 was based upon the types of projects that were required to address the capacity issues in those years.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. The average unit costs do not accurately reflect the expected spending due to specific work scopes needed for each project. New substation project costs can vary based on considerations such as the substation design, electrical capacity required, and site conditions. For example, the new Mercury Substation will have one transformer and four circuits compared to the new Quicksilver Substation which will have two transformers and eight circuits. The Quicksilver Substation transformers will have larger electrical capacities than the Mercury Substation transformer resulting in higher transformer purchase costs.

Existing substation project costs can vary based on whether a full rebuild is required (*i.e.* obsolete design), partial rebuild is required (*i.e.* adding a new circuit), equipment replacement is required (*i.e.* transformer, voltage regulator, recloser), load transfers to an adjacent substation can be utilized, or if a mobile substation is required to maintain electrical service during the project. Additionally, the nature of transformer progress payments is such that spending may occur in a given year with no corresponding unit to divide by, meaning it would be mathematically difficult to even calculate a unit cost.

3. ELECTRIC OTHER PROGRAM

Q. What is included in the Electric Other Program?

A. Company witness Duke introduces the Electric Other Program in her direct testimony. The Electric Other Program includes the following sub-programs in the test year:

- Computers and Equipment
- System Control Projects

The Electric Other Program also includes the Tools sub-program, which is addressed by Company witness Partlan in her direct testimony.

a) Computers and Equipment

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Computers and Equipment sub-program.

A. The Computers and Equipment sub-program consists of the capital costs to purchase and replenish computer equipment for electric distribution purposes.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Computers and Equipment sub-program?

A. The Company is projecting bridge period capital expenditures of $100,000 in this sub-program, as shown in Exhibit A-87 (EMD-3), line 39, column (k). This spending is primarily for new field devices such as Toughbooks and laptops for employees. The Company is projecting test year capital expenditures in this sub-program of $75,000, as shown in Exhibit A-87 (EMD-3), line 39, column (l). As shown in Exhibit A-87 (EMD-3), line 39, column (m), this amount is lower than the five-year average spending for this sub-program.

Q. Why were spending levels in this sub-program higher in 2022?

A. Higher spending levels in 2022 were related to a Scheduling Optimization project. In 2022, the Company developed and deployed a new digital tool called "iSchedule" as a part of this effort. This project was addressed in Case No. U-21389.

b) System Control Projects

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the System Control Projects sub-program.

A. The System Control Projects sub-program consists of projects to improve management of the distribution system, by improving operations of control centers, streamlining operations, and improving remote control capabilities to improve safety and reliability. This work includes operating technology enhancements and operations center modifications.

Q. What is included in operating technology enhancements?

A. Operating technology enhancements improve functionality and operations of the:

- System Control Center ("SCC") - Monitor and maintain the 46 kV and 138 kV HVD Systems;
- Distribution Control Center ("DCC") – Monitor and maintain LVD Substations and 3-phase backbone of the LVD system; and
- Work Management Centers ("WMC") - Monitor and maintain the LVD system and responsible for outage restoration by managing crews on the LVD system.

These three groups are responsible for monitoring the system and ensuring reliable power is delivered to all customers. To manage a system of the Company's size, these centers use technology specifically designed for real-time operations. Specific enhancements can vary from year to year.

Q. What is included in operations center modifications?

A. This consists of additional equipment and infrastructure to improve the Emergency Operations Center ("EOC"). These initiatives are typically identified during the after-action-reviews ("AAR") for each event. Examples of these initiatives include small upgrades to office spaces to accommodate personnel and larger computer monitors to increase situational awareness.

Q. What benefits will customers realize through the Company completing work in the System Control Projects sub-program?

A. Improving monitoring and control capabilities on the distribution system helps streamline operations and reduce the impact of any single fault, reducing interruptions for customers. The technology enhancements and control room modifications will better enable employees to provide safe and reliable electricity.

Q. What is the basis for the Company's projected investment in System Control Projects in the instant case?

A. In Case No. U-21870, the Company projected test year investment of $145,000 for this sub-program, and this amount was approved by the Commission. In the instant case, the Company is maintaining projected investment levels at approximately the same amount, as shown in Exhibit A-87 (EMD-3), line 41.

Q. What has been the historical actual spending in the System Control Projects sub-program for the past five years?

A. The Company's historical actual spending is shown in Figure 61 below.

FIGURE 61
SYSTEM CONTROL PROJECTS HISTORIC EXPENDITURES

2021	2022	2023	2024	2025	5-Year Average
$1,193,498	$2,179,436	$41,000	$896,000	$57,000	$873,000

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program is variable on a year-over-year basis primarily because this sub-program consists of discrete one-time projects that will not necessarily be repeated from year to year. Technology programs may cost a relatively large amount to purchase in one

year, but then once purchased there is no additional spending for that technology in subsequent years. Test year spending in this sub-program is lower than the five-year historical average for two primary reasons. First, as the Company plans to transition to a Unified Control Center, less investment is needed in the existing facilities that will be replaced. Second, work that has historically been performed in the HVD Operations Projects investment category is being transitioned largely to the HVD Lines Reliability sub-program, reducing the total amount spent in System Control Projects.

B. Unplanned Spending Programs

1. HVD STRATEGIC CUSTOMERS NEW BUSINESS

Q. What is the purpose of the New Business Program?

A. The overall New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid, as discussed by Company witness Duke in her direct testimony. Because of the Company's obligation to serve customers in its service territory, the Company generally is required to provide the requested interconnections.

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the HVD Strategic Customers New Business sub-program.

A. The HVD Strategic Customers New Business sub-program consists of the capital costs to meet the new business needs of large C&I customers that are too energy-intensive to be served by the area LVD system, addressing both existing customers and potential new customers to locate a new facility in Michigan. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles, conductors, and metering to connect new C&I customers.

Q. How does the Company plan projects and develop investment projections in this sub-program?

A. Projected test year spending amounts are based on planned projects to meet customer commitments, plus projects with a high probability of moving forward in the near future, such that bridge or test year spending amounts would be needed, as discussed in more detail below. These costs are net of any expected contributions made to the Company by customers in support of their project. Customer service inquiries in this sub-program are continuous and are driven by customer business needs. Unlike many of the Company's other capital programs, this sub-program and its timing of projects and investments are driven to meet the needs and expectations of specific customers. The timeline from a completed customer agreement to a final connection can vary from six months to two or more years. While some projects are known well enough in advance to be captured in a rate case filing, in other cases they are not.

Q. Please explain how the Company identifies projects to account for spending in this sub-program.

A. The Company identifies projects as they are requested by customers. Customers typically contact the Company's Business Customer Care team, who refers the customer to the HVD planning engineer for the corresponding geographic location. The customer will identify their location, proposed new maximum electrical demand, a proposed schedule for the new electric load to come online, as well as other information. The HVD planning engineer performs studies and develops conceptual cost estimates for any required new or upgraded Company facilities to serve the new load, including any Contribution in Aid of Construction ("CIAC") costs applicable to the customer. The conceptual cost estimates are developed by

the Company's project management team using derived costs, where available, based on historical actual costs for similar projects. The costs are also further refined with support from the Company's design and project management departments prior to customer agreements being executed, taking into consideration the specifics of each project such as the location, expected site conditions, and up-to-date material and labor costs. If costs are agreed to by the customer, a schedule for the work is developed.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Strategic Customers New Business sub-program?

A. The Company is projecting HVD Strategic Customers New Business capital expenditures of $43,005,000 in the bridge period, and $48,064,000 in the test year, as shown in Figure 62 below.

FIGURE 62
HVD STRATEGIC CUSTOMERS NEW BUSINESS INVESTMENT CATEGORY
PROJECTED EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units	Benefits
Projects	$43,005,000	10	$48,064,000	5	Obligation to Serve, Economic/Community Impact
Total	**$43,005,000**	**10**	**$48,064,000**	**5**	

Q. What is the basis for the Company's requested spending level for the HVD Strategic Customers New Business sub-program in this filing?

A. The projected spending for the bridge period and the test year is primarily based on projects to which customers have committed to moving forward. These projects are listed in Exhibit A-156 (KKL-3), page 15, and Exhibit A-157 (KKL-4), page 12.

Q. Why does one of the projects in Exhibit A-156 (KKL-3), page 15, have a projected expenditure of negative $295,000?

A. Construction for this project was completed in December 2025. During the project close-out process, unused equipment and materials were returned to inventory, resulting in credits to the project. As final costs were reconciled and actual expenditures trued up, these credits exceeded remaining charges, producing a net negative projected spending of $295,000.

Q. Have customers committed to moving forward with all of the listed projects?

A. Yes, with two exceptions. First, Exhibit A-156 (KKL-3), page 15, line 8, and Exhibit A-157 (KKL-4), page 12, line 3, both refer to a new 138 kV dedicated customer's substation in east Michigan. This project is associated with a customer request that is expected to develop quickly once execution begins. To meet the customer's expected ramp-up schedule, the Company has begun procuring equipment and engineering.

Second, Exhibit A-156 (KKL-3), page 15, line 9; and A-157 (KKL-4), page 12, line 4, both refer to a capacity increase at an existing 138 kV dedicated customer's substation in west Michigan. At the time of filing the instant case, this is in final negotiations with a signed contract expected in the second quarter of 2026.

Q. Can you provide any further details about the first of those projects mentioned?

A. Regarding the new 138 kV dedicated substation in east Michigan, the Company expects that this will progress and has already begun procurement and engineering, as noted above. Even if this project were to not progress, the Michigan Economic Development Corporation ("MEDC") and the relevant local government's Economic Development Organization have indicated that they still intend to develop the site in question into a "Gold" certified site as part of the MEDC's MI Sites Program, and this development would include requirements

for the Company. Specifically, receiving a Gold certification would require the Company, at a minimum, to develop an engineering plan for utility improvements to extend service to property boundary and/or provide minimum capacities within required timeframes. Receiving a Gold certification also involves requirements for other parties; for example, the local government must ensure water utilities are available. In the event that the dedicated substation project does not progress, the Company is committed to supporting the MEDC and the local government in this site development effort. To support this, equipment needs to be procured and engineering started.

Q. What is the MI Sites Program?

A. The MI Sites Program is a comprehensive site readiness initiative, administered by the MEDC, designed to build a strong portfolio of development-ready industrial sites across Michigan. Through consistent statewide criteria, the program evaluates site strengths and provides actionable insights to help communities advance along the readiness pathway. Training and guidance are provided at each step to support progress and success. The MI Sites Program classifies potential development sites as Bronze, Silver, or Gold[1].

Q. Are there any benchmarking or industry references outside of the Company's specific experience that substantiate the need to support site readiness efforts undertaken by state and local governments?

A. Yes. As previously outlined in the direct testimony of Company witness Megan L. Hayward in Case No. U-21870, the Site Selectors Guild, an association of global professional site selection consultants, partnered with Development Counsellors International to complete

[1] Details can be found at: https://www.michiganbusiness.org/contentassets/59fbc74e32df4bec94edd8872b88a43a/mi-sites-program-summary-2026.pdf

The State of Site Selection 2024 report[2], a primary research study that identifies the top trends impacting the facility location decision-making process in the United States and globally. The study found that 87% of Guild members strongly agree that resource shortages (including with utilities) have challenged or compromised project timelines (page 10). "Utilities/Infrastructure" continues to be identified as a top factor impacting the site selection industry in 2024 (page 11). Furthermore, 79% of Guild members identified "Utilities/Infrastructure" as *the* top factor impacting site selection in 2024 for Industrial customers, and 64% identified the availability of development-ready sites as the third most critical factor to industrial customers (page 12).

The quotes below from the Site Selectors Guild study are consistent with the Company's experience:

> In the U.S., the supply of industrial sites with adequate labor, utilities and access has been significantly reduced due to economic growth in the industrial sector over the last 10 to 15 years. In terms of the site selection process, intensified screening of sites at early stages of projects is critically important to verify fatal flaws. [Mark Williams, Strategic Development Group Inc. (page 17 of the report)]

> The biggest challenge facing the industrial market is the lack of development-ready sites with desired available utility capacity. When utilities require upgrades to meet capacity needs, you are looking at a 24- to 36-month timeline for that to occur, which rarely meets a company's plant startup timeline these days. Everything is moving at a faster pace, so if you are a community that truly wants to attract new jobs and investment to your community, you must get your sites and infrastructure prepared ahead of these search inquiries. There is just no way around it. [Michelle Comerford, Biggens Lacy Shapiro & Company (page 23 of the report)]

> So many projects have required massive amounts of electric power and often other utilities, which has strained capacity in nearly all locations that are typically attractive to

[2] Available at https://siteselectorsguild.com/research/the-state-of-site-selection-2024/.

> manufacturers…..Lengthy waits to get transformers – sometimes quoted at 36 months now – quickly eliminates otherwise top locations. Smaller to midsized projects, which could become the norm again after this big push on electric vehicles, semiconductors and solar production abates, are a bit less impacted and have more choices, but the capacity constraints will start affect their choices and certainly their costs. [Phil Schneider, Schneider Strategy Consulting LLC (page 41)]

This remains true today, and other statewide partners have included overall site readiness as a priority to position Michigan for long-term growth. Economic Development Leaders for Michigan ("EDLM"), a coalition of the state's regional economic development organizations, announced their Top 10 Priorities for Statewide Growth and Prosperity[3] in August 2025. One of those priorities is to continue to invest in site readiness. EDLM members urge state policymakers, business leaders, and stakeholders across Michigan to support and champion these initiatives as part of a collaborative strategy to secure Michigan's future economic success.

> "If Michigan is serious about long-term economic stability, we need to continue to invest in order to generate economic returns today and tomorrow. The ten legislative priorities championed by Economic Development Leaders for Michigan represent the high-return tools our state needs to retain and attract the next generation of talent and businesses. A robust, fully funded economic development toolbox doesn't just help local businesses succeed—it drives good jobs for our residents, strengthens our communities, and grows our state's revenues over time. These are the tools we need to do just that."
>
> - Jennifer Owens, President, Lakeshore Advantage

[3] https://www.edlm.org/top-10-priorities

Q. What has been the historical actual spending in the HVD Strategic Customers New Business sub-program for the past five years?

A. The Company's historical actual spending in this sub-program for the past five calendar years is shown in Figure 63 below.

FIGURE 63
HVD STRATEGIC CUSTOMERS NEW BUSINESS HISTORIC EXPENDITURES ($000)

2021	2022	2023	2024	2025	5-Year Average
$20,268	$4,280	$11,071	$57,836	$40,821	$26,855

Q. Why does historical spending in this sub-program show significant year-to-year variation?

A. Spending in this sub-program can be variable from year to year because the projects and investments undertaken are relatively few and are specifically tailored to the needs of the customers requesting the work. This was particularly illustrated in 2021 and 2024, when the Company worked on a couple of large customer projects in this sub-program that accounted for the higher costs in those years. The amount of anticipated load and redundancy requirements determines the required number and size of large substation transformers, which is typically a large driver of costs in this sub-program. For example, one of the large projects that occurred in 2024 was for a new 138-kV four-transformer dedicated customer substation with four 75 MVA transformers, with project spending of approximately $18 million in 2024, and expected total project spending of $45.6 million over three years. Conversely, a project in 2020 for a new single-transformer dedicated customer substation with a 30 MVA transformer had a total project cost of about $3.5 million. There can also be some projects that are relatively minor upgrades required to serve smaller customers that cost less than $100,000. The work completed in this

sub-program is performed to provide new or upgraded facilities required to serve new or existing customers.

Q. Why is the requested spending level for the bridge period and the test year greater than the historical average spending in this sub-program?

A. The requested spending is higher than the historical average, but it is still within the range of annual spending needed over the past five years. As stated above, spending in this sub-program is based on unique customer requests and projects that are tailored to the needs of the customer requesting work. Similar to 2021 and 2024, but on an even larger scale, the bridge period and the test year contain several large projects that are needed to serve several very large customers. These include a new larger 138 kV dedicated customer substation needing four 75 MVA transformers to serve a large customer in east Michigan; a new larger customer requiring two 138 kV dedicated customer substations needing two 75 MVA transformers and three 150 MVA transformers to serve a large customer in west Michigan; a new 46 kV dedicated customer substation to serve a customer in east Michigan; and a capacity increase to a 138 kV customer substation to serve a customer in west Michigan. These projects span both the bridge period and the test year with larger than historical spending required to complete them. The projected spending amounts for these projects are shown in Exhibit A-156 (KKL-3), page 15, and Exhibit A-157 (KKL-4), page 12.

Q. What benefits do customers receive through the Company completing work in the HVD Strategic Customers New Business sub-program?

A. The investments in this sub-program are necessary for C&I customers to expand their facilities, allowing those customers to further develop their businesses. This also benefits the broader economy of the state of Michigan. Increased large new customer connection

and load additions provide the benefits of job development, and other state and local revenue streams associated with business expansion. Figure 64 below illustrates examples of the benefits and impacts of two committed projects in progress (included in the bridge period) and the associated community impact.

FIGURE 64
HVD STRATEGIC CUSTOMERS NEW BUSINESS RECENT PROJECT IMPACTS

Project Name	Community Impact
New 138 kV dedicated customer Substation in east Michigan	The customer is constructing a new facility with the potential to create more than 1,000 new jobs.
New 138 kV dedicated customer Substation in west Michigan	The customer will be expanding their existing location, with the potential to create up to 150 new jobs.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. The historical unit costs for this sub-program reflect projects that vary significantly in size and scale. Each project in this sub-program is specifically designed to meet the needs of the individual C&I customer who requests the project.

2. <u>METRO NEW BUSINESS</u>

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the Metro New Business sub-program.

A. The Metro New Business sub-program responds to electrical energy needs of new construction and existing metered locations served by the Company's Metro underground

territories. The Company typically needs to extend both the underground civil infrastructure, such as ductwork, and the electrical system to accommodate new business requests.

Q. How does the Company generally handle new business requests on the Metro system?

A. Metro New Business customers are connected to the system at no cost, in accordance with rate administration and billing rules in the Company's MPSC-approved tariffs, specifically Section C6.2 Underground Policy, Part F. These customers commonly fall into two categories: (i) *primary service*, typically large commercial, government, and healthcare facilities; and (ii) *secondary servic*e, typically commercial retail use, mixed use, or residential buildings in accordance with the Company's MPSC-approved tariffs, specifically C1.6 General Provisions of Service and C4.3 Application of Residential Usage and Non-Residential Usage.

Q. What benefits will customers realize through the Company completing work in the Metro New Business sub-program?

A. Metro New Business projects primarily benefit the customers being connected. Service connections vary by electrical demand. Primary services are typically provided in a loop feed, primary selective, or split bus design that provides reliable service. Secondary services are radial in nature and sized to the service meter and customer electrical panel size to allow for future electric growth without subsequent upgrades. Economic growth in the six metro downtowns depends on the ability of new residential and commercial customers to access utilities, including electricity.

As with other work in the New Business Program, all customers ultimately benefit from the load growth driven by new customers, as system-wide fixed costs are spread across

a broader base. The projected spending level will allow the Company to provide a new service installation to every customer who requests it.

Q. How does the Company identify Metro New Business projects?

A. The Company identifies projects as they are requested by customers, as is common throughout the New Business Program. The Company has identified projects needed to fulfill customer requests for the bridge period, which are listed in Exhibit A-156 (KKL-3), page 16. The Company has also identified projects, for the test year, which are listed in Exhibit A-157 (KKL-4), page 13. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects.

Q. Are there projects that are not currently known, but that could be reprioritized to take place during the test year, if circumstances change?

A. While Metro New Business projects can be identified in advance on some occasions, project timelines can be fluid because customers' own development timelines often change in response to various factors. The projects listed in the exhibits are those that the Company expects to perform in the bridge period and test year. However, it is possible that one or more customers could request a project for 2026 or later, and then subsequently request the Company perform the work sooner if the customer has a change in timeline.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro New Business sub-program?

A. The Company is projecting Metro New Business capital expenditures of $9,223,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 4, column (k), and $7,737,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 4, column (l). The Company's

historical actual spending in the Metro New Business sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 4.

Q. How does the Company develop its projected expenditures in this sub-program?

A. In some cases, customers contact the Company in advance, allowing for Metro New Business project costs to be determined and planned for in longer-range spending forecasts. However, even with advance notice, customers' respective developments may take years to come to fruition, as customers seek funding and address other issues relative to economic development in urban core areas. Therefore, even advance notice Metro New Business projects may not be completed on the originally proposed timeline. In other cases, customers contact the Company later in their development process, with desired service within that same year, meaning those Metro New Business project costs cannot be accounted for in longer-term forecasting. Therefore, the Company also uses analysis of historical spending levels to forecast the level of investment needed in this sub-program. The Company's projected bridge period and test year spending level in Metro New Business is in line with recent experience. There have been many inquiries, in addition to the identified projects, supporting that the projected Metro New Business expenditures for the test year will be higher than the past three years.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. The Company's recent investment in Metro New Business was at its highest in 2024, as there was significant economic development and urban renewal, with corresponding construction work, in several of the downtown areas served by the Company's Metro systems. For example, in Grand Rapids the amphitheater civil project required an investment of approximately $3,450,000 and the first phase of civil work for the Kalamazoo

Event Center required an investment of approximately $4,830,000. These higher than historical costs were mainly driven by expansion of the Metro system to serve these new business loads. The Metro New Business expenditures in 2022 and 2023 were lower than other recent years due to project developer delays related to post-pandemic supply chain and inflationary pressures, and lack of construction labor resources.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure to project the cost of a project in this sub-program. Metro projects have a wide variance in size, scope, and work required, ranging from $100,000 to as high as $5,000,000 per project.

3. HVD LINES AND SUBSTATIONS DEMAND FAILURES

Q. What is the purpose of the Demand Failures Program?

A. The overall purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system, as discussed by Company witness Duke in her direct testimony. When the Company replaces failed equipment, the associated capital expenditures are part of the Demand Failures Program. The work in the Demand Failures Program is emergent; it is planned, prioritized, and completed as issues arise, with specific projects not planned far in advance. The HVD Lines and Substations Demand Failures sub-program specifically addresses failures on HVD lines and substations.

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the HVD Lines and Substations Demand Failures program.

A. The HVD Lines and Substations Demand Failures sub-program supports the capital replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer

service and maintain reliability. This sub-program replaces assets that have failed in the field, including HVD substation equipment, HVD poles and switches, and HVD cross-arms and insulators. The HVD Lines and Substations Demand Failures sub-program consists of the following investment categories addressing actual failures:

- Pole replacements
- Pole top assembly replacements
- Switch (including MOABS) replacements
- Miscellaneous other replacements
- HVD substation failure projects

The first four cited investment categories support projects on HVD lines.

Q. What types of investments are included in the HVD substation failure investment category?

A. The HVD substation failure investment category supports the replacement of equipment and infrastructure that has failed within an HVD substation and includes (but is not limited to) power transformers, circuit breakers, circuit switchers, capacitors, switches, bushings, station batteries/chargers, regulators, voltage transformers, and facilities (such as fences, gates, and driveways).

Q. What benefits will customers realize through the Company completing work, in the HVD Lines and Substations Demand Failures sub-program?

A. This sub-program is essential for the restoration of service to customers for the Company to meet its obligation to serve. As mentioned above, this sub-program is also utilized to address failed assets as they are identified prior to those failures causing an interruption to customers. The projected bridge period and test year amounts provide for the level of

investment necessary in HVD Lines and Substations Demand Failures needed to support capital repair or replacement of projected failed HVD equipment to address interruptions and meet the Company's obligation to serve customers.

In the majority of HVD Lines failures, customers are interrupted, and the Company must restore those customers as quickly and safely as possible. In 2025, there were 69 HVD Line failures with an average of 2,850 customers interrupted per event, excluding outages occurring during an MED. For those situations where an HVD line failure occurs and customers are not interrupted, such failures put the system into a non-standard configuration, reducing system resiliency, that would likely result in a much larger outage if a second failure occurs. For HVD substations, outages to customers due to individual equipment failures are much rarer due to redundancies in the substations but they can be of significant size when they do occur. A 2024 failure of an oil circuit breaker at Verona substation near Battle Creek resulted in extended outages for 5,000 customers for more than 14 hours. Even more critical was the loss of system resiliency and redundance that prevented quick isolation of more than an additional 8,700 customers who were then without power for more than 22 hours. When an individual piece of equipment in a substation fails, the Company still needs to address that failure, even if no customers are interrupted, in order to maintain levels of redundancy.

Q. How does the Company identify and prioritize HVD Lines and Substations Demand Failures sub-program projects?

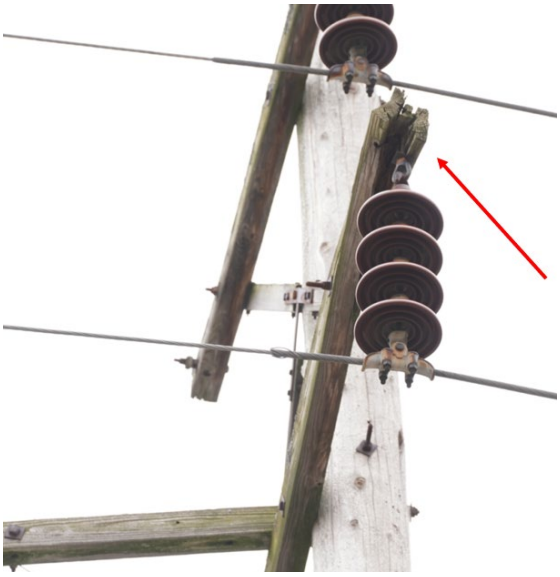
A. For HVD Lines, the Company determines work needs based on real-time HVD line component failures or very short-term imminent failures. The Company immediately responds to component failures resulting in customer outages identified from calls from

customers, third parties, or by alarms from the SCADA system. Once notified, system operators and/or crews are quickly dispatched to locate the electric fault and restore power to customers. Data from digital relays and line sensors can often be used to pinpoint the location of the fault, allowing crews to find the location faster.

Component failures that do not cause a line to trip, but decrease the integrity of the line, are addressed within weeks or months once discovered. These anomalies are identified through routine annual helicopter patrols, biannual ground patrols, or through calls from customers, employees, or third parties. Examples include floating phases (when a phase wire becomes unsecured from an insulator), broken insulators, broken crossarms, broken poles, or broken static wires. Figure 65 below provides two examples of Priority 1 anomalies identified during helicopter inspections.

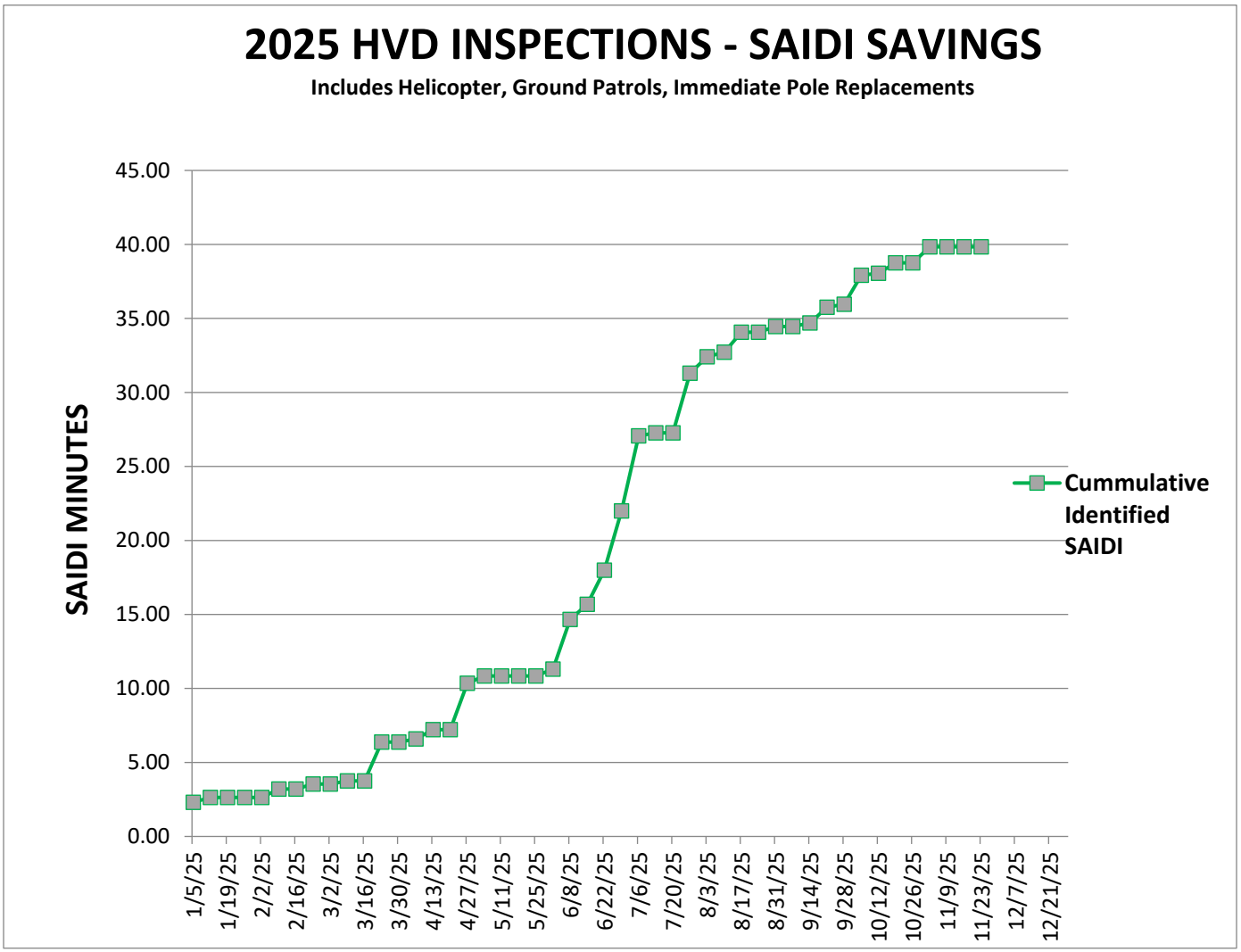
FIGURE 65





In 2025, the identification and correction of Priority 1 and 2 anomalies like the ones shown above, before those anomalies resulted in customer outages, avoided an estimated 39.84 SAIDI minutes. Figure 66 below shows the timeline in which failures are identified and corrected. The failures are assigned a projected SAIDI minute benefit that is realized after the correction has been made.

FIGURE 66



For HVD Substations, the Company acts based on real-time failures, anomalies, and issues discovered through an annual inspection process. If an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately. If the equipment anomaly is not currently causing a customer outage, it will be addressed at a future point in time through the HVD Substation Reliability Program. Some projects, such as HVD transformer replacements with longer lead times, may be delayed if other replacements are identified that have a higher risk of failure or have failed in service.

Q. Why is the Company requesting approval for these expenditures in this proceeding?

A. Failure to repair faults that result in customer outages in a timely manner inhibits the Company's obligation to serve. Failure to address failed equipment that does not result in customer outages increases the risk of customer outages in the future if not addressed in a timely manner. The spending in this sub-program maintains customer reliability or in the event of a fault, restores customers quickly and safely.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Lines and Substations Demand Failures sub-program?

A. For the bridge period, the Company is projecting HVD Lines and Substations Demand Failures capital expenditures of $11,657,000, as shown in Exhibit A-87 (EMD-3), line 7, column (k). For the test year, the Company is projecting HVD Lines and Substations Demand Failures capital expenditures of $10,333,000, as shown in Exhibit A-87 (EMD-3), line 7, column (l). The bridge period and test year spending by investment category is broken down in Figure 67 below. Individual HVD substation failure projects can range widely in scope and cost, from small transformer replacements costing $12,000 up to large transformer replacements costing $2,000,000. This variation makes it impractical to project a unit total. Projected spending on HVD substation failure projects is based on historical actual spending without respect to units.

FIGURE 67
HVD LINES AND SUBSTATION DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Pole replacements	$2,387,470	80	$2,877,857	97
Pole top assembly replacements	$984,608	113	$1,186,846	137
Switch replacements	$735,631	6	$886,730	7
Miscellaneous/other replacements	$312,262	18	$376,400	22
HVD substation failure projects	$3,876,030	n/a	$4,672,167	n/a
Total	**$11,657,000**		**$10,333,000**	

Q. How did the Company develop its projected expenditures in this sub-program?

A. The spending forecast is based on the historical average for this sub-program, accounting for the upward trend in spending.

Q. What has been the historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five years?

A. The Company's historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five calendar years is shown below in Figure 68. In 2022, a failed cap switcher at the Litchfield substation cost $600,000; and the beginning of a failed transformer replacement project at the Halsey substation cost $1.2 million. Both of these contributed to higher spending. In 2023, the transformer replacement at the Halsey substation was completed, totaling an additional $700,000; and major transformer replacements at the Wackerly substation for $1.4 million and the Beaver Creek substation for $2.3 million accounted for the increased spending in this investment category. In 2024, a failed circuit breaker at Verona substation and resulting damage to adjacent equipment increased spending in this category by $1 million. In 2025 the failure of underground lines

on Union Street cost $400,000 while the cost to replace the substation transformer at Trillium sub contributed $1.6 million to this investment category.

FIGURE 68
HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES ($000)

2021	2022	2023	2024	2025	5-Year Average
$6,050	$10,015	$13,524	$11,705	$13,380	$10,932

Q. What are the historical unit costs for each of the HVD Lines and Substations Demand Failures investment categories?

A. Historical unit costs for each lines-related investment category are identified in Figure 69 below.

FIGURE 69
HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES

Investment Categories	2021	2022	2023	2024	2025
Pole replacements	$18,800 /project	$33,100 /project	$30,465 /project	$45,714 /project	$37,356 /project
Pole top assembly replacements	$8,300/ project	$10,302/ project	$10,052 /project	$9,707/ project	$11,114 /project
Switch replacements	$132,600 /project	$143,000 /project	$114,875 /project	$169,950 /project	$320,334/ project
Miscellaneous other replacements	$37,300 /project	$4,750 /project	$3,187 /project	$11,931 /project	$40,406 /project

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. Yes, with the exception of the miscellaneous other replacements investment category. Since the miscellaneous/other replacements investment category encompasses a wide variety of projects, the unit costs in that category show wide variation. It is possible to see variation

in other investment categories, as accessibility and specific equipment factors can create increases in individual project costs. All other unit cost variation can be explained in that these are project level costs and a project can have one or multiple pole/pole tops or switches that are being replaced on a single project.

4. LVD SUBSTATIONS DEMAND FAILURES

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Demand Failures sub-program.

A. The LVD Substations Demand Failures sub-program supports capital repair or replacement of failed LVD substation equipment to restore customer service and maintain reliability of electrical service. Work in the LVD Substations Demand Failures sub-program is planned and executed when an event has occurred. LVD Substations Demand Failures projects are divided into four investment categories:

(i) voltage regulators;

(ii) reclosers;

(iii) transformers; and

(iv) other equipment.

Q. What has been the average failure population of the three main LVD substation components in the past five years?

A. Based on the five-year average from 2021 through 2025, the Company has experienced approximately three LVD substation transformer failures (approximately 0.31% of population); 40 recloser failures (approximately 0.75% of population); and 59 voltage regulator failures (approximately 1.12% of population) per year. These historical failure rates are used to project investment needs going forward in this sub-program.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Demand Failures sub-program?

A. The projected test year amount provides for the level of investment necessary in LVD Substations Demand Failures to support capital repair or replacement of failed LVD substation equipment to address interruptions, maintain service quality, and meet the Company's obligation to serve customers. Absent investment in this category, customers would remain without electric service or experience unacceptable service quality when substation equipment fails. For example, if a substation transformer serving 5,000 customers failed, electric service to those customers would not return until the substation transformer was replaced or a mobile substation was temporarily installed. If a substation voltage regulator serving 1,000 customers failed and was not replaced, those customers could eventually experience electrical equipment damage or electrical equipment may not function properly due to inadequate service voltage.

Q. Can you give an example of a recent LVD Substations Failure event?

A. In 2025, during a routine inspection and preventive maintenance program, it was identified that a transformer bank at the North Muskegon Substation had a load tap changer in an abnormal position caused by a control-mechanism issue. To prevent a potential transformer failure, the bank was proactively removed from service. The associated substation circuits were transferred to other distribution circuits in the area supplied by neighboring substations. This transfer resulted in a short, five-hour outage affecting 1,512 customers. However, had the issue not been identified in advance and the transformer ultimately failed, the resulting outage would have been significantly longer in duration and more disruptive.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The work in this sub-program is essential to restoring interrupted electrical service to customers or to restore the safe and reliable operation of the substation.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Demand Failures sub-program?

A. For the bridge period, the Company is projecting LVD Substations Demand Failures capital expenditures of $13,200,000, as shown in Exhibit A-87 (EMD-3), line 8, column (k). For the test year, the Company is projecting LVD Substations Demand Failures capital expenditures of $11,000,000, as shown in Exhibit A-87 (EMD-3), line 8, column (l). The Company's historical actual spending in the LVD Substations Demand Failures sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 8.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's requested spending levels for the bridge period and test year are based on projected failure rates, which are in turn based on historical failure rates as defined above. The projected bridge period and test year capital expenditures were determined by evaluation of the 2021 through 2025 actual spend and based on projected future costs.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test years for each investment category as identified in Figure 70, based on the Company's average failure rates over the historical period of 2021 through 2025.

FIGURE 70
LVD SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Regulators	$4,800,000	80	$3,600,000	60
Reclosers	$2,400,000	48	$1,800,000	36
Transformers	$4,500,000	3	$4,500,000	3
Other Equipment	$1,500,000	30	$1,100,000	22
Total	**$13,200,000**	**161**	**$11,000,000**	**121**

Q. Please explain the year-over-year variation in spending in this sub-program.

A. In 2021, the Company replaced two transformers that failed in 2020 but were replaced in 2021. Baum Street and Dewey Substations both have two transformers, so when one of the transformers failed at each substation in 2020, electric service was restored by temporarily transferring the impacted customers to the other transformer until the failed transformer replacement projects were completed in 2021. In 2023, six emergent projects contributed to the majority of spending within the Other Equipment Replacements investment category. All six projects required mobile substations and three of those projects required substation structure modifications resulting in a higher project cost. In 2024, the Company replaced 30 more voltage regulators than were originally forecasted, replaced 14 more reclosers than were originally forecasted, and 12 emergent projects contributed to the majority of spending within the Other Equipment Replacements investment category. The 12 emergent projects consisted of various equipment failures such as transformer bushings, transformer cooling fans, substation switches, and lightning arresters. In 2025, the Company replaced 23 more voltage regulators than were originally forecasted and eight emergent projects contributed to the majority of spending over the original forecast within the Other Equipment

Replacements investment category. The eight emergent projects consisted of various equipment replacements such as transformer bushings, transformer load tap changers, and substation structure modifications.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. Unit costs at an investment category level can be misleading. Equipment costs within an investment category can vary among various voltage and size ratings, and accurate failure predictions within each equipment voltage and size ratings are not possible. For example, within the voltage regulator investment category, there are four main voltage ratings and more than six size ratings, resulting in various potential failure costs for the multiple regulator sizes within each voltage rating group. Within the transformer investment category, there are three high-voltage ratings, six main low-voltage ratings, and four main size ratings, resulting in various potential failure costs for the multiple transformer sizes within each high-voltage and low-voltage rating groups.

Unit cost is not a good measure to project spend for the Other Equipment investment category due to varying work scopes that are generally required for each project. For example, failed lightning arrester replacements could range from $1,000 to $10,000 depending on voltage rating and quantity; failed switch replacements could range from $5,000 to $100,000 depending on voltage rating, size rating, and quantity; and failed transformer bushing replacements could range from $50,000 to $250,000 depending on voltage rating, quantity, and mobile substation needs.

Finally, the purchase costs of some types of equipment have been increasing. Most notably, the Company has seen a significant increase in the purchase cost of transformers,

which has resulted in a higher apparent unit cost for that investment category compared to recent history.

For each investment category in this sub-program, projected unit costs are based on recent actual purchase orders placed by the Company and therefore reflect recently available cost data for the equipment in question.

5. METRO DEMAND FAILURES

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the Metro Demand Failures sub-program.

A. The Metro Demand Failures sub-program involves the replacement of failed cables, transformers, and civil infrastructure within the Company's Metro systems. Metro Demand Failures costs are highly dependent on the type of asset that fails. Civil assets such as manholes, vaults, and duct banks are highly labor intensive with correspondingly high restoration costs. Electrical asset failures are variable, as spare components (*i.e.* transformers and switches) are kept in local storerooms and can be replaced immediately. Primary cables are kept in storerooms and may be immediately replaced or replaced at a later date given their loop or primary selective design. Secondary and service cables are designed in a radial nature, so secondary and service failures are immediately replaced to restore service.

The Company projects its needed investment level in this sub-program based on historical averages and trends. In this filing, spending in Metro Demand Failures is divided into three investment categories:

(i) Cable Failure and Replacement;

(ii) Transformer Failure and Replacement; and

(iii) Civil Infrastructure Failure and Replacement.

Q. Why does the Company perform replacement of electrical assets in this sub-program?

A. Electrical assets in Metro vaults may fail due to age, deterioration, standing water, and runoff contaminants (*e.g.* salt). The most common electrical assets that fail are Metro transformers, primary cable, and secondary cable. If a primary cable fails, the Company identifies potential switching schemes to immediately restore service to customers. After the fault is isolated and customers are restored, there are times when the Metro system is no longer in a loop or primary selective configuration (i.e. it no longer has feeds from multiple directions) and must be repaired. A design will be created for permanent repairs. By leaving this faulted section isolated for a long period of time, there would no longer be a way to restore service to customers from that direction. If a transformer fails, it is replaced with a spare unit. If a secondary cable fails, a new cable is pulled in a spare conduit adjacent to the failed cable. The failed cable is cut at both ends and removed, creating another spare conduit.

Q. What are the general factors that contribute to the need for investment in the Metro Demand Failures sub-program?

A. Many factors contribute to deterioration of the cabling, equipment, and civil infrastructure in the Metro systems, including age of the system and public damage. The Company commonly sees several specific problems caused by deteriorating electrical equipment including:

- primary cable failures;
- transformer and other electrical equipment failures; and
- secondary and services failures.

The Company commonly experiences public damage-related failures resulting from:

- Work performed in the ROW without notification to the MISS DIG system;
- Improper directional boring techniques used by contractors performing work for other utilities in the ROW; and
- New business and redevelopment engineered plans, including parts of the ROW, with poor surveying and notification to the Company.

Q. What benefits will customers realize through the Company completing work in the Metro Demand Failures sub-program?

A. Absent investment in this category, customers would remain without electric service or the redundant portion of the metro system would remain out of service indefinitely. Leaving the redundant portion of the system out of service would eliminate the availability to complete restoration of other unplanned events. The projected bridge period and test year amounts provide for the level of investment in Metro Demand Failures needed to support capital repair or replacement of failed metro equipment to address interruptions, and to meet the Company's obligation to serve customers.

Q. Why is the Company requesting approval of these expenditures in this proceeding?

A. The work in this sub-program is essential to restore interrupted electrical service to customers served by the metro underground system or to make immediate repairs to the civil infrastructure to protect the public.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery in the Metro Demand Failures sub-program?

A. The Company is projecting capital expenditures of $532,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 10, column (k), and $350,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 10, column (l). The Company's historical actual spending in the Metro Demand Failures sub-program, along with the bridge period and test year forecasts, are shown in Exhibit A-87 (EMD-3), line 10.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Company's projected bridge period and test year spending are based on a continuation of the test year spending level approved by the Commission in Case No. U-21870.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Before 2020, the Company invested more than average in this sub-program to address imminent failure issues with civil and electrical infrastructure in the Flint and Jackson Metro systems. Today, that work would be addressed in the Metro Rehabilitation sub-program. This rehabilitation work has reduced the cost of failures in the Metro system. Beginning in 2021, the Company experienced fewer actual failures requiring equipment replacement, resulting in generally declining spending due to rehabilitation and reliability investments. In 2025, actual spending is reflected as a negative number due to the timing of closeout credits hitting the sub-program; these credits offset actual spending.

Q. Does an average unit cost accurately reflect the expected spending per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program because of the variance in work required to address failures, which range from $4,500 to $60,000 per project. Additionally, the number of units completed each year is small, which inhibits reliable unit cost metrics.

6. HVD ASSET RELOCATIONS

Q. What is the purpose of the HVD Asset Relocations sub-program?

A. The overall Asset Relocations Program includes capital investments to relocate assets, as described by Company witness Duke in her direct testimony. The HVD Asset Relocations

sub-program includes the capital investments to relocate 46 kV and 138 kV lines on a reactive basis.

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the HVD Asset Relocations sub-program.

A. The HVD Asset Relocations sub-program includes the capital investments necessary to facilitate non-reimbursable relocations of 46 kV and 138 kV lines required to accommodate usage of public ROW and required transmission project work. The cost of relocating lines in the road ROW, or in some instances on private property, is typically the responsibility of the Company. In other cases, such as relocation work requested by businesses and residential customers, the requesting party will pre-pay or reimburse the Company for the cost of the relocation, but the transactions will still pass through this sub-program.

Q. Which parties typically request HVD Asset Relocations projects?

A. There are four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

Q. Please explain each category of parties that may request HVD Asset Relocations.

A. Municipalities and other government agencies (including the Michigan Department of Transportation ("MDOT")) request HVD Asset Relocations to facilitate their civil engineering projects, such as road and bridge widening and improvements, repairs to municipal facilities, work on water and sewer lines, municipal building and structure construction projects, and streetlight and traffic signal modifications. The HVD Asset

Relocations allow those agencies to safely access their facilities without having to work around HVD infrastructure. Relocations may be temporary or permanent.

METC or another transmission owner may request HVD Asset Relocations to accommodate their transmission projects. For example, the Company may have HVD lines attached to METC structures below transmission lines. Depending on the nature of the project, METC may reimburse the Company for associated costs on a case-by-case basis.

Private landowners and businesses request HVD Asset Relocations to accommodate additions, landscaping, and other construction projects on their property. One relatively common request is for overhead lines to be repositioned to allow for building additions.

Internal Company departments may require HVD Asset Relocations to accommodate their own projects they are planning, such as a 2022 project requested by the HVD Planning Department on the National City, Prescott, and Whitestone Point Lines, where poles were relocated to facilitate the rebuild of the HVD Arenac Substation.

Q. What are some examples of recent HVD Asset Relocations projects?

A. In 2021, the Company relocated four structures on the Grand Valley 46 kV Line in Kent County to accommodate a project by the Kent County Road Commission. The Company also relocated the Millers Point 138 kV line to support MDOT's work to rebuild US-131/KL Avenue bridge in Kalamazoo County in 2023. These examples and others are shown in Figure 71 below.

FIGURE 71
HVD ASSET RELOCATIONS RECENT EXAMPLES

Project Name	Order Created/ Work Completed	Net Capital
Virgina Park Line Relocate Structure 159-166. Requested by Customer.	3/1/2023 – 5/1/2024	$ 237,890
Millers Point 138 kV line. Relocate line to support MDOT rebuild of US-131/KL Ave Bridge. Requested by MDOT.	6/28/18 – 10/02/2023	$ 4,481,153
Upton Line. Relocate Structures 193-199. Requested by customer.	9/9/2021 – 8/19/2022	$ 545,700
Ramona Line. Relocate structures for new I-96 on ramp. Requested by MDOT.	4/13/2021 – 4/15/2022	$ 581,400
Okemos Line. Relocate Structures 1167 and 1168 due to Okemos Road project. Requested by Ingham County Road Commission.	9/26/2020 - 7/14/2022	$ 477,900

Q. How does the Company identify HVD Asset Relocations projects?

A. As discussed above, projects are typically identified by four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

Q. Did the Company consider any alternative approaches for these investments?

A. When an asset must be relocated in this sub-program, there is generally no alternative to doing so. However, each project in this sub-program is evaluated by the HVD Lines Engineering group for the best method of achieving the customer's objective (typically to move the line out of the way of something that will be built in that space), at the lowest cost alternative.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the HVD Asset Relocations sub-program?

A. The Company is projecting HVD Asset Relocations capital expenditures of $1,198,000 in the bridge period, and $899,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 13.

Q. How did the Company develop its projected expenditures in this sub-program?

A. The Commission approved test year spending of $899,000 in Case No. U-21870. The projected bridge period and test year spending in this case is aligned with this approved amount. In the absence of any pre-identified significant projects in this case for this sub-program, Consumers Energy is projecting no changes in investment for this sub-program.

Q. What benefits will customers realize through the Company completing work in the HVD Asset Relocations sub-program?

A. The primary purpose of this sub-program is to relocate existing HVD lines at the request of customers, and to fulfill the needs of customers and other external parties. This sub-program also helps improve reliability through the installation of new equipment that meets the Company's current design standards.

Q. Are there any projects that span multiple years?

A. Yes. Since most projects take several months to design and construct, it is common for projects to span from one year into another (see the examples of projects in Figure 67 earlier in this section).

Q. What are the historical costs in this sub-program over the past five years?

A. The historical costs in this sub-program are shown in Figure 72 below.

FIGURE 72
HVD ASSET RELOCATIONS HISTORICAL SPENDING

2021	2022	2023	2024	2025	5-Year Average
$1,709,000	$2,565,000	$5,319,000	$845,000	$610,000	$2,210,000

Q. Are any of the costs in the five historical years a significant outlier in this sub-program?

A. In 2023, significant spending occurred as a result of ongoing work to relocate multiple HVD lines for MDOT, with those large projects totaling $4,397,000.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Most projects in this category are customer requested and customer funded. A typical project will be paid for and completed in the same year, resulting in a net-zero spend. Some projects span multiple years, resulting in a credit one year for work performed in another. The remaining projects are those where HVD lines are in the public ROW for which the Company is obligated to cover the cost. There are typically only a few of these projects, but they do range in cost from the single pole relocation for $20,000 to projects like the current US-131/KL Avenue Bridge rebuild requested by MDOT, for over $4 million. As a result, an average unit cost is not a useful or insightful cost measure in this sub-program.

7. METRO ASSET RELOCATIONS

Q. Please explain what projects, activities, and other types of work will be enabled by the expenditures in the Metro Asset Relocations sub-program.

A. The Metro Asset Relocations sub-program responds to both internal and external requests to relocate or modify civil structures, such as manhole chimneys and castings due to road grade changes, either in a public ROW or on private property, and underground or padmounted electric facilities and service points not related to a new business request. The Company's Metro relocation projects can be on a demand basis or a planned and coordinated basis, with the Company making it a priority to meet mutually agreed upon deadlines and milestones, and to perform the required work within the requested ROW.

Projects requested by other departments within the Company may be planned further in advance, rather than on a demand basis.

Q. What is the typical nature of external relocation requests in the Metro Asset Relocations sub-program?

A. External relocation requests come from state agencies, municipalities, downtown development authorities, and private developers. State agencies and municipalities may request relocations to accommodate for upcoming civic improvement work for a specific ROW. Typical improvements include storm and sanitary sewers, water mains, street improvements, and streetscapes. Municipalities, downtown development authorities, and private developers may request relocations to convert overhead electric systems to underground civil and electrical systems, generally to improve aesthetics. These requests typically require the customer to provide a non-refundable engineering deposit for the Company to perform a feasibility study to find an underground path for the civil infrastructure system.

Q. Does the Company request reimbursement for a Metro relocation request?

A. Yes, the Company seeks reimbursement for a third-party initiated Metro relocation request on a case-by-case basis. Commonly, reimbursement is sought when a third party requests the existing overhead distribution system be converted to underground. The same process applies to those third parties requesting a vacation of the ROW—the Company will seek reimbursement to convert existing overhead distribution to underground distribution, and seek a permanent easement from the new property owners of the vacated ROW.

Q. Does reimbursement match the cost of relocation?

A. Yes, when the Company establishes reconcilable contracts with the requesting third party, the Company will either credit or invoice the requesting party at the end of the project for its actual costs for the conversion of overhead distribution to underground metro distribution.

Q. What is an example of a recent externally requested Metro Asset Relocations project?

A. The Company and the City of Kalamazoo are engaged in a two-year coordination of utilities project, allowing the company to rebuild its metro facilities in the Kalamazoo Avenue ROW. The City of Kalamazoo will also be rebuilding its water, storm and sewer utilities along with other utility partners such as the Company's gas business and various telecommunications companies. This is part of the City of Kalamazoo Public Works initiative to transform its one-way street network back to two-way traffic flows in downtown Kalamazoo.[4]

The Company also plans to partner with the City of Grand Rapids on a coordination of utilities project as the city rebuilds and consolidates Ionia Avenue NW and Division Avenue N from I-196 to Coldbrook Street NW. This project is part of the much larger project being undertaken by the City of Grand Rapids, involving a grant from the MEDC, in the North Monroe area of downtown Grand Rapids[5].

[4] https://www.kalamazoocity.org/Community/Projects/Streets-for-All/
[5] https://www.mlive.com/news/grand-rapids/2026/01/grand-rapids-to-transform-northeast-downtown-neighborhood-with-13m-project.html

Additionally, the Company is undertaking a large coordination of utilities with MDOT and the City of Flint on the rebuild of the M-21 Court Street/Fifth Street corridor through downtown Flint.[6]

Q. What is the Company's process for planning Metro Asset Relocations projects in response to internal requests?

A. Projects triggered by an internal request are considered during the Metro planning process, which takes place in July and August of each year. Company engineering planners, with responsibility for planning and design of the affected Metro system area, prepare scope documents and estimated project costs during this process. Internal requests are triggered by various workgroups, such as Substation Planning, LVD Planning, or HVD Planning. An example of an internal request is in Jackson, where Substation Planning plans to replace the Ingham Substation transformer bank (refer to Exhibit A-156 (KKL-3), page 9, line 10). Metro will support this project by converting its electrical vaults from delta operations to grounded wye and reconfigure the primary circuits for better substation loading and performance. Future substations projects include Oak Street in Jackson, and a voltage conversion project and substation exit work in Battle Creek and Flint.

Q. What benefits will customers realize through the Company completing work in the Metro Asset Relocations sub-program?

A. Although the primary purpose of this sub-program is to accommodate the needs of customers, external parties, and other internal workgroups, the sub-program does help improve reliability through the installation of new equipment. When the Company replaces

[6] https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Projects-Studies/Studies/Feasibility/M-21/M-21-Corridor-Study-Report.pdf?rev=3212df3ecd074bc1a6695e60dc1aa424&hash=0D0B1167E0F1842E94035D280114D96B

old or obsolete equipment with new equipment as part of a relocation project, reliability is improved since the new equipment has up-to-date design standards and less general wear and tear. Customers connected directly to these assets receive these reliability benefits.

Q. Please identify the projects that will be accomplished with the requested spending level in the Metro Asset Relocations sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-156 (KKL-3), page 17, and for the test year, listed in Exhibit A-157 (KKL-4), page 14. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Metro Asset Relocations sub-program?

A. The Company is projecting Metro Asset Relocations capital expenditures of $26,201,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 14, column (k), and $18,270,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 14, column (l). The Company's historical actual spending in the Metro Asset Relocations sub-program, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 14.

Q. What is driving the Company's projected increase in investment in Metro Relocations?

A. The Company's spending in the Metro Asset Relocations sub-program is based on external requests, and therefore varies from year to year based on the requests that the Company receives. The Company is addressing more requests than in recent years, tied to municipal projects in Grand Rapids, Saginaw, and Kalamazoo. The associated identified Metro Relocations projects determine the amount of investment needed for this sub-program.

Q. How did the Company develop its projected bridge period expenditures?

A. The Company has identified relocation projects in Exhibit A-156 (KKL-3), page 17, that supports the bridge period spending level, and projected expenditures are based on these projects. Projects listed in the exhibit with no associated spending are projects where the Company expects to be fully reimbursed by customers.

Q. How did the Company develop its projected test year expenditures?

A. The spending amount for the test year is supported based on substation projects that will require new exits to the Metro system and the planned coordination of utilities projects for 2027 and early 2028, each of which require Metro Relocations work. The Company has identified relocation projects in Exhibit A-157 (KKL-4), page 14.

Q. Are there any projects that span multiple years?

A. Yes, due to the size and scope of some Metro Asset Relocation projects, it is common for the civil assets to be installed in one year with the electrical assets installed in the year following. This has been identified on the Quicksilver project in Grand Rapids, along with the Kalamazoo Avenue project and M-21 corridor project.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Investment in this sub-program depends heavily on the volume and complexity of requests for relocation. Most recent years have set new levels of investment. Continued growth in these metro areas is expected to sustain a need for higher-than-average capital expenditures in this sub-program. Costs are ultimately being saved as coordination of utility projects share road restoration costs among all participants and traffic detour interruptions one time.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this sub-program. There is a wide variance of scale and scope among the work required.

VII. BIDIRECTIONAL FLOW

Q. Please elaborate on the Commission's directive to provide analysis on bidirectional flow in its final Order in Case No. U-21870.

A. In Case No. U-21870, Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan ("MNSC") witness Caroline Palmer argued that "(o)ne-way power flow is no longer the reality" on the electric distribution system and that "DERs are making bidirectional power flow more common on the distribution system, in turn providing generation and other services to higher voltage customers who previously only benefited from centralized generation delivered at the transmission or primary level." MNSC therefore recommended that as the Company develops an analysis of bidirectional flow on its system, "it should incorporate such empirical data into the EAC report or other power system mapping to identify the extent to which higher-voltage customers utilize and should pay for downstream assets."[7] The Commission found MNSC's argument regarding bidirectional power flow "compelling," and found "persuasive" the argument that "power flow is not the only measure of (distribution system) utilization." The Commission directed the Company to "provide

[7] Case No. U-21870 March 27, 2026 Order pg. 362-363

empirical data in the EAC report or other power system mapping to identify the extent to which higher voltage customers utilize and should pay for downstream assets."[8]

Q. Is the Company providing empirical data on bidirectional power flow in response to the Commission's directive in Case No. U-21870?

A. Yes. The Company believes that power flow can be a reasonable measure of system utilization.

To comply with the Commission's directive, the Company gathered hourly power flow data for its 914 DSCADA distribution transformers in 2025. After evaluating that data, the Company confirmed that any bidirectional flow from the LVD system back on to the HVD system is *de minimis.* Only 0.21% of total MWh flowed in the reverse direction from LVD primary (between 2.4 to 25 kV) to the HVD system. Of the Company's 914 distribution transformers with DSCADA, 891 had no reverse power flow, 31 had less than 1% reverse power flow, and only three had reverse power flow at or above 50%. While the Company is able to track the occurrence of bidirectional flow at certain substations using DSCADA data, the Company does not have the capability to produce comprehensive datasets that capture the full extent of bidirectional flows across the entire distribution system. This limitation is especially pronounced between the LVD secondary and LVD primary systems, where downstream customer density is high and devices capable of sensing reverse flow to the LVD primary system are few. Advanced Metering Infrastructure ("AMI") can inform when DER interconnections are exporting to the LVD secondary system, but cannot provide visibility of where exports flow beyond the point of interconnect.

[8] Case No. U-21870 March 27, 2026 Order pg. 371

Q. Does the Company incorporate bidirectional flow from the LVD system when planning investments in the HVD system?

A. No. In addition to the immateriality of that load discussed above, due to the intermittent nature of DERs connected to the LVD system, the Company must plan HVD investments for the case when the DERs are not providing reverse flow. Therefore, there is no impact to HVD investment decisions due to bidirectional flow.

VIII. SUMMARY

Q. Please provide a brief overview of your testimony and the intent of investing in HVD capital programs to support the Company's electric distribution system.

A. My testimony provided an overview of the HVD system and associated capital investments to improve reliability and resiliency of the system while serving new customers to support economic development in the state of Michigan. The testimony provided detail of each HVD capital investment program, the basis of planned investments, and benefits. All HVD capital investments outlined in my testimony are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap. My testimony highlighted increased spending in several areas in order to meet the reliability and asset health goals defined in the Reliability Roadmap.

As supported throughout my testimony, the Company's projected HVD capital expenditures are summarized in Figure 73 and should be approved by the Commission.

FIGURE 73
HVD CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	$464,890,000	$434,899,000

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Scott A. McPhail II, and my business address is 3201 E. Court St., Flint, Michigan 48506.

Q. In what capacity are you employed?

A. I am employed as Director of Grid Automation by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. In 2008, I graduated from the University of Michigan-Dearborn with a Bachelor of Science degree in Industrial & Systems Engineering. I earned a Master of Business Administration from Eastern Michigan University in 2015.

Q. Describe your experience and current responsibilities at Consumers Energy.

A. I began my career with Consumers Energy full-time in 2003 as an engineering technician, with a focus on gas distribution system design. Over the years I have held various roles involved with economic analysis, revenue recovery, and the Company's Regulatory Affairs department. In 2016, I supported the rollout of the Company's Lean operating system, the Consumers Energy Way ("CE Way"). After supporting a number of business units on the implementation of the CE Way, I joined the Electric Emergency Preparedness team as the Manager. My responsibilities encompassed the preparedness of the Company for storm events that impact the electric grid. I have led many major restoration events for the Company to ensure safe and quick restoration of customers. In April 2024, I accepted the role in Grid Automation as Director. The responsibilities in my current role include overseeing the strategy, deployments (field devices, software systems), and integration of

proven technology into the business units, providing new capabilities within the Grid Automation portfolio.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC cases:

Case No. U-21585	Electric Rate Case; and
Case No. U-21870	Electric Rate Case.

Q. How is your testimony organized?

A. Below is a Table of Contents outlining my testimony.

I. Purpose and Structure 3
II. Introduction to Grid Automation 4
III. Capital Investments Summary 7
IV. Distribution Automation 10
Fault Location Isolation and Service Restoration 15
Voltage Regulator Controllers 20
Metro Modernization 28
IP-Enabled Remote Terminal Unit 31
IP-Enabled IED 34
V. Planning Systems Modernization 36
DER Optimization 44
VI. Electric Distribution Asset Management 45
VII. Weather Stations 51
Overview 51
VIII. Summary 56

I. Purpose and Structure

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's Grid Automation/Modernization plan, and to request approval of the projected capital expenditures to continue the implementation of that plan.

Q. How is the direct testimony structured?

A. My testimony is structured as follows:

- **Section I** is the purpose and structure of the testimony.
- **Section II** describes how the Company defines Grid Automation and provides an overview of how modernizing the grid will support the Company's broader electric strategy and the enablement of the foundational capabilities that customers expect.
- **Section III** provides an overview of Grid Automation capital investments.
- **Section IV** describes capital investments into a new program titled Distribution Automation ("DA") and outlines progress the Company has made with Fault Location Isolation and Service Restoration ("FLISR").
- **Section V** discusses the Planning Systems Modernization investment category.
- **Section VI** describes the progress made on the Distribution Asset Management's Asset Repository.
- **Section VII** discusses investment into Company-owned Weather Stations and the progress made.
- **Section VIII** provides a closing summary of my testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-158 (SAM-1)	Distribution Automation Reliability Benefits;
Exhibit A-159 (SAM-2)	Test Year Distribution Automation Projects;
Exhibit A-160 (SAM-3)	Voltage Regulator Controller BCA;

Exhibit A-161 (SAM-4)	Bridge Period Voltage Regulator Controller Projects;
Exhibit A-162 (SAM-5)	Voltage Regulator Controller Inventory Record;
Exhibit A-163 (SAM-6)	Metro Modernization Reliability Benefits;
Exhibit A-164 (SAM-7)	DistAM Benefits; and
Exhibit A-165 (SAM-8)	Weather Stations Reliability Benefits.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

II. Introduction to Grid Automation

Q. Describe the objectives of Grid Automation and how customers benefit.

A. A core objective of Grid Automation is to reduce the frequency and duration of customer outages. The Company invests in grid infrastructure and adopts technologies proven effective across the utility industry. This often involves upgrading to the latest generation of grid equipment. Over the past several decades, advancements have led to new grid equipment with enhanced sensors and improved communication capabilities, resulting in better performance. The Company's goal is to identify and incorporate these proven, updated grid technologies into its deployment programs. The Company has adopted a standardized approach to its deployment called the Technology Enablement Process ("TEP"). This repeatable process benefits customers due to deployment of predictable technologies that improve the customer experience through fewer and shorter outages, and improved power quality.

In the U.S. Department of Energy ("DOE") study titled *Distribution Automation: Results from the smart grid investment grant program*[1] the major findings show that DA technologies and systems achieve substantial grid impacts and benefits that meet, and often exceed, pre-project expectations, including:

- Improved fault location, isolation, and service restoration capabilities;
- Improved distribution system resilience to extreme weather;
- More effective equipment monitoring and preventative maintenance;
- More efficient use of repair crews and truck rolls; and
- Improved grid integration of selected distributed energy resources ("DERs").

Grid Automation also supports improved power quality for customers by controlling voltage through line conditioning devices. Not only is this needed to meet regulatory standards, but also because improved power quality means customer equipment can operate more efficiently, and the overall power generation supply required is conserved.

The final area of focus is to improve grid safety for the public and co-workers, such as electric line workers. Consumers Energy's projects aim to leverage automated and remote operations thus reducing hazard exposure of its co-workers and providing quicker response to risks that impact the public.

[1] Office of Electricity Delivery and Energy Reliability. (2016). *Distribution Automation: Results from the Smart Grid Investment Program.* U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

Q. How does the Company's Grid Automation plan support the broader electric strategy?

A. Grid Automation is a fundamental part of the electric distribution business. As discussed by Company witness Emily M. Duke, Grid Automation directly supports the Company's objective of building the grid of the future as the Company installs new technological capabilities on the distribution system. Grid Automation investments on the electric distribution system significantly improve safety, reliability/resiliency, affordability, and enable a clean, equitable grid. The Grid Automation portfolio will continue to deliver on new and improved capabilities through proven technologies, advanced applications, and foundational management systems.

Q. How does the Company's Grid Automation plan support the Company's reliability strategy?

A. Grid Automation is a foundational piece of the Company's Reliability Roadmap, which is a blueprint to strengthen the Company's electric grid. By enhancing the ability for meters, sensors, and automation devices to work together to monitor, isolate, and automatically respond to anomalies and interruptions more effectively, Grid Automation investments result in reliability, resiliency, grid efficiency and improved safety benefits, including but not limited to:

- Providing voltage optimization to deliver energy efficiently year-round and also reduce energy demand at peak times of the year;
- Providing remote monitoring and visibility to see real-time power flow and voltage throughout the grid;
- Establishing communication with field devices, enabling real-time load monitoring and fault detection;
- Establishing remote control to field devices, enabling real-time settings management;

- Enabling remote monitoring and control of field devices to reduce the duration and frequency of outages; and
- Remotely deenergizing the grid to protect co-workers and the public.

As described in each investment's section below, these investments are a core foundation of the Company's long-term plan to improve reliability and resiliency.

Q. Are there any updates to the Grid Automation strategy?

A. Since the creation of the Grid Modernization strategy in 2020, industry trends have changed. For example, the advent of artificial intelligence ("AI") and advancement in predictive analytics is changing how the utility delivers improved service to its customers. Regulatory requirements are in place, such as Federal Energy Regulatory Commission ("FERC") Order 2222 and Michigan Public Act 235 of 2022 ("PA 235"), promoting more clean generation across the electric distribution system. The Company has completed a Grid Automation Capabilities Roadmap to meet regulatory requirements and deliver what customers expect from their energy provider. The Grid Automation Capability Roadmap is less focused on what specific projects should be deployed but more focused on what the grid must be able to do over the next 10 years. This provides for flexibility as industry trends in technology change, the Company can stay focused on the outcome the grid must deliver leveraging proven technologies used at other utilities.

III. Capital Investments Summary

Q. Please describe how investments are categorized in the Grid Automation portfolio.

A. As discussed by Company witness Duke, the Company's Grid Automation investments are part of the overall Reliability Program (see Exhibit A-103 (EMD-19)).

Q. Are there investments that are new to the Grid Automation Portfolio?

A. Yes. This testimony will describe a new investment titled Distribution Automation.

Q. What is the Company's total projected Grid Automation investment in this case?

A. For the bridge period, the Company projects to spend $15,183,000 as shown in Exhibit A-87 (EMD-3), line 20, columns (k). For the test year, the Company projects to spend $8,260,000 as shown in Exhibit A-87 (EMD-3), line 20, column (l). The Company's projected Grid Automation investments are explained in greater detail in the sections below.

Q. Please explain how the capital expenditures will be allocated across the investment categories in the bridge period and the test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 1 below.

FIGURE 1
GRID AUTOMATION CAPITAL EXPENDITURES ($000)

	Bridge Period (Jan '26 - Apr '27)	**Test Year (May '27 - Apr '28)**
Distribution Automation (DA)	**7,494**	**4,340**
Line Reclosers & Remote-Capable Switches	443	3,690
FLISR	0	0
Voltage Regulator Controllers	6,276	0
Metro Modernization	305	650
IP-Enabled RTU	190	0
IP-Enabled IED	280	0
Planning Systems Modernization	**3,970**	**2,840**
Distribution Asset Management – Asset Repository	**1,850**	**1,080**
Weather Stations	**1,870**	**0**
Total	**15,183**	**8,260**

Q. What has been the historical actual spending in the Grid Automation/Modernization Program for the past five calendar years?

A. The Company's historical calendar year annual spending in the Grid Automation/ Modernization Program for the past five calendar years is shown in Figure 2 below, and can also be found as shown in Exhibit A-87 (EMD-3), line 20.

FIGURE 2
HISTORICAL GRID MODERNIZATION SPENDING ($000)

Grid Automation Sub-Program	2021	2022	2023	2024	2025
All other Sub-Programs (previously Grid Modernization: Automation)	51,153	39,411	25,781	14,596	15,768
Advanced Technologies Projects	23,697	13,934	3,253	5,524	4,411
Substation Comm Upgrades	(696)	(529)	4	42	0
Total	**74,154**	**52,816**	**29,038**	**20,162**	**20,179**

Q. Please explain the decline in total program spend compared to historical years.

A. Historically, the Grid Automation/Modernization program included large scale deployments such as Supervisory Control and Data Acquisition ("SCADA"), Line Sensors, and Voltage Regulator Controllers, as shown in the bridge period in Figure 1. The Company expects to complete the deployment of Voltage Regulator Controllers by the end of 2026. The remaining projects in this current bridge year are of smaller scale and/or include software. The DA program is a grid scale deployment initiative that has larger capital spending that generally falls outside the test year. The larger deployment of the DA program is expected to begin in the 2028/2029 calendar years.

IV. Distribution Automation

Q. Please describe DA.

A. DA uses various sensors, controls, communication networks, and intelligent electronic devices ("IED") to monitor the grid in real-time, to coordinate and operate equipment automatically based on the needs of the grid thus providing an improved experience for customers. DA began over 15 years ago when the first automated devices to reroute power in the event of an outage were deployed on the low voltage distribution ("LVD") system and has continued to this day with the deployment of Automatic Transfer Reclosers ("ATR"), line sensors, and other SCADA enabled equipment. DA on the electric grid is a wholistic approach to address the electric grid for current day challenges and preparing for the future in a way that can utilize the available technological advances, such as DERs and communicating devices, to automate more tasks thus providing customers with an improved experience.

Q. Why is DA needed?

A. The Commission has been clear in its expectation to improve reliability and resilience. The Company agrees that more investment is needed to provide the level of service customers expect. Reducing the impact of electric outages and increasing the speed at which customers are restored is aligned with the Company's Reliability Roadmap. When outages happen from severe weather, infrastructure failure, or trees outside the right-of-way DA can limit the impact and dramatically speed up the restoration. The Commission has established Rules and reporting to monitor the Company's performance. These include:

1) Service Quality and Reliability Standards for Electric Distribution Systems[2]

2) Financial Incentives and Disincentives workgroup Case No. U-21400[3]

Next, the Company's 2024 performance in System Average Interruption Frequency Index ("SAIFI") is 2nd quartile while its Customer Average Interruption Duration Index ("CAIDI") performance is 4th quartile[4]. This further shows more investment is needed to reduce the duration of outages customers experience, in other words reduce CAIDI.

Lastly, beyond customer outages, DA provides for improved power quality and the ability to integrate DERs into the grid providing improved situational awareness and the capability to call upon DERs to support grid needs.

Q. How is the DA program different from the ATR deployments?

A. The deployment of ATRs, as covered by Company witness Jennifer M. Partlan, has delivered strong reliability improvements for customers for years (see Ms. Partlan's Figure 35). These proven devices constitute the backbone of the Company's effort to utilize automation to restore outages quickly to some customers and avoiding outages altogether for other customers. With the advancements the Company has made with its FLISR efforts, discussed later in my testimony, coupled with the proven success of ATRs and line sensors deployments, additional sectionalizing of the grid will further limit the impact of outages to customers. After 2028, it's expected the Company's ATR program will be absorbed into this broader DA program, thus providing more grid capabilities. This is a natural evolution

[2] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/grid-sec/Service_Quality_Standards.pdf?rev=2b7e0af6da1148389309eac7b997dc7f&hash=442A9A60A890AA22DBC575F4F4138B7B

[3] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000cgb0WAAQ

[4] https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics

to operate the grid wholistically with grid devices and systems working together to further improve service to customers.

Q. What is included in the DA program?

A. The DA program will initially focus on the deployment of reclosers through the continued deployment of ATRs and the installation of Remote-Capable Switches shown in Figure 1. In future years, outside this test year, additional investments will be necessary including (a) SCADA-enabled single phase reclosers, (b) NOVA Triple Single recloser communication upgrades, (c) metropolitan ("metro") vault switches, (d) underground padmount switches, (e) construction of circuits for tie points, (f) necessary communications through Field Area Networks, (g) Volt/VAR Optimization, (h) integration with DERs, and (i) system upgrades/integration into the Advanced Distribution Management System ("ADMS").

Q. How will customers benefit from DA?

A. Automating the grid through the DA program will provide reliability and resiliency benefits for customers. More SCADA-enabled devices on the grid means more places to switch and transfer in the event of an outage, with a higher density of devices leading to smaller and smaller groups of customers that experience an outage. Additional benefits can be evaluated from the increasing use of SCADA-enabled devices across the grid by automating various operational and maintenance processes such as streamlined inspections, testing, lifecycle management, engineering tasks, planned switching operations, and emergent remote operational needs.

Q. What safety improvement can be made from the automation of the grid?

A. Improved public safety is anticipated in two key ways. First, in the event of the public coming in contact with Company facilities (like a car-pole accident), having increasing numbers of SCADA-enabled devices improves the likelihood that a nearby device can be remotely opened to eliminate the hazard; further, it is also more likely that the close proximity of such a device will mean that the fewest customers possible get affected by that emergency power shutdown. Second, with systems to automate monitoring the devices and identifying anomalies of imminent failure using AI-based tools, the Company can shift to being increasingly proactive by replacing equipment before the equipment fails. Currently, the Company is using line sensors to conduct waveform analysis using AI anomaly detection to fix outages before they happen. In 2025, over 1 million Customer Minute Interruption ("CMI") was avoided through this proactive detection program. As for employee safety, there are also two main benefits to deploying DA on the grid. First, DA devices and systems will send real-time data to the control center which improves safety when crews can know exactly what state the system is currently configured in before being dispatched to a job or outage. This is especially important during emergency operations or when the grid is in an abnormal operating condition. Second, the ability to safely operate a device remotely from a control center reduces traffic and arc flash exposure for the Company's employees.

Q. Has the Company Completed a Benefit Cost Analysis ("BCA") for the DA investments?

A. The primary purpose of the DA program is to improve reliability, which has been provided and has historical evidence of benefits delivered to customers supported by the Company's

historical ATR program covered by Company witness Partlan. A CMI has been provided in Exhibit A-158 (SAM-1), which also contains a revenue recovery calculation. The CMI demonstrates the estimated reliability benefit from adding new ATRs within existing loops given their historical operational performance and the incremental improvement when the customers affected would be reduced further with additional ATRs. Installing the 29 new ATRs proposed in the project list is expected to avoid an estimated 3.2 million CMI (or a 1.7 minute reduction to all-weather System Average Interruption Duration Index ("SAIDI")).

Q. How will FLISR aid DA?

A. The Company has made great progress in its efforts to have FLISR functioning within the ADMS. FLISR can be described as the "brains" of the automated grid. FLISR will determine fault location, isolate the fault, conduct real-time load studies to determine the most optimal form of switching, and automatically issue those commands to the devices on the circuits thus restoring customers. FLISR requires the DA program's SCADA equipment such as ATRs/reclosers and remote-capable switches, hence FLISR and DA work together. As the Company grows in its capabilities, DERs could be used to aid in restoration. See below in my testimony for specific details about the active FLISR effort.

Q. How does the Company plan to prioritize the circuits for DA?

A. The Company plans to develop a prioritization model building upon existing tools and incorporate zonal health scores (covered by Company witness Partlan), high Customers Experiencing Multiple Interruptions ("CEMI") areas, high circuit SAIDI/CAIDI, and environmental justice ("EJ") communities. In Exhibit A-159 (SAM-2), the 29 ATR sites specifically chosen in the project list for DA were picked because the existing ATR loops

had both 1) a history of operating due to recent outages that yielded CMI benefits, as well as 2) a larger-than-average customer count per existing ATR on the loop. Introducing additional reclosers on these specifically targeted loops will deliver the greatest benefits by reducing the size of any future outages by the largest customer count.

Q. Please identify the projects that will be targeted with the requested spending level in the DA investment category.

A. The Company has identified projects for the test period, and they are listed in Exhibit A-159 (SAM-2). In the test year, the $190,000 difference between Figure 1 and Exhibit A-159 (SAM-2) ($3,690,000 - $3,500,000 = $190,000) accounts for the purchase of remote capable switches to be included as part of the broader DA program.

Q. Are DA investments included in the Investment Recovery Mechanism ("IRM")?

A. No.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the DA investment?

A. The Company is projecting DA capital expenditures of $4,340,000 in the test year. A large investment is needed to automate the electric grid and the Company is taking a prudent path to scale this program. Key Performance Indicators ("KPIs") will be established to measure and validate customer benefits, similar to the current ATR program discussed by Company witness Partlan. KPIs will include CMI avoided and SAIDI avoided.

Fault Location Isolation and Service Restoration

Q. Please summarize the objectives of FLISR.

A. FLISR is an ADMS software application that uses DA communicating grid equipment, such as line sensors, reclosers, regulators, and capacitor banks to quickly detect and locate where faults are on the system, then automatically re-route power, minimizing the number

of customers impacted. FLISR will consist of three key components: software enablement within the ADMS, hardware deployment (part of the DA program), and Company process updates. This project will include the integration of electric distribution system data as well as the validation of the application solution capability. An important final piece of the implementation includes the creation and modification of operating procedures to ensure safe and efficient procedures are trained and used with the Company's Grid Operators within the Control Room.

Q. What work was completed in 2025 to support FLISR?

A. In 2025, the Company conducted cross-functional stakeholder design and configuration efforts to establish end-user experience expectations and how to configure FLISR to operate in a way that suits all the operations teams. A key software upgrade to ADMS was completed (finalized in January 2026) to pave the way for the core features needed to support FLISR implementation. The Company has an established roadmap for 2026 and beyond to execute the configuration, validation, and process development of the FLISR module for the initial field deployments.

Q. What work will be completed in 2026 to support FLISR?

A. In 2026, the Company will continue to execute on several main tasks. The first is to finalize the configuration of the FLISR software module in ADMS and perform end-to-end scenario validation on a variety of likely situations to confirm FLISR solutions. Second is enablement support, which will establish future state alignment with all engineering and operations stakeholders to update Control Room procedures and train Grid Operators that manage the electric distribution grid. Finally, 2026 will see the implementation of the first

FLISR networks on the electric grid. Circuits have been selected with each location having increased complexity to be managed by the FLISR software using DA devices.

Q. Can you share more details about the circuits that were selected for the first FLISR Networks using DA?

A. The first circuits selected for FLISR implementation are based on the likelihood of the network operating for a fault in the near future to demonstrate the success of the FLISR solution. Data analysis was conducted to determine which existing ATR loops had the highest count of operations. The Pettis Road01_Ratigan01 loop (see Figure 3), North Kent headquarters ("HQ") and Haskelite02_Haskelite03 loop (see Figure 4), Grand Rapids HQ, both have operated 12 or more times since 2021. Following those two first networks, a more complicated combination of existing loops is being pulled together as a single FLISR network to prove out the system's capability to handle complex switching solutions. The Cowan_Lake-1 network, North Kent HQ, is being established creating a network with three ties over four circuits. See Figure 5.

FIGURE 3
NORTH KENT HQ: PETTIS_ROAD-1 FLISR NETWORK ONE LINE

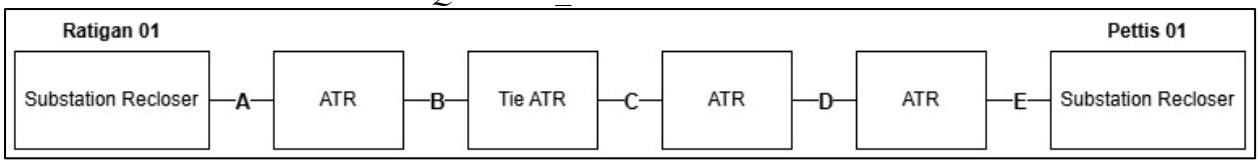


FIGURE 4
GRAND RAPIDS HQ: HASKELITE-1 FLISR NETWORK ONE LINE

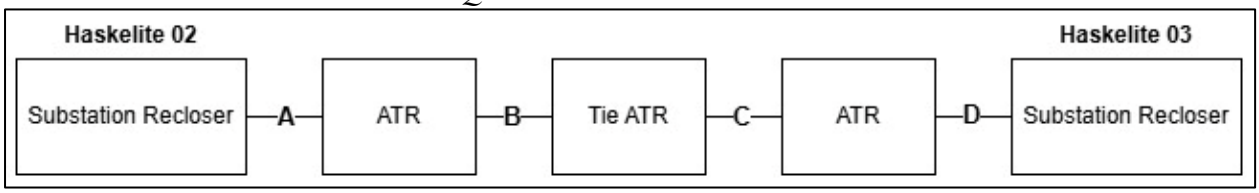
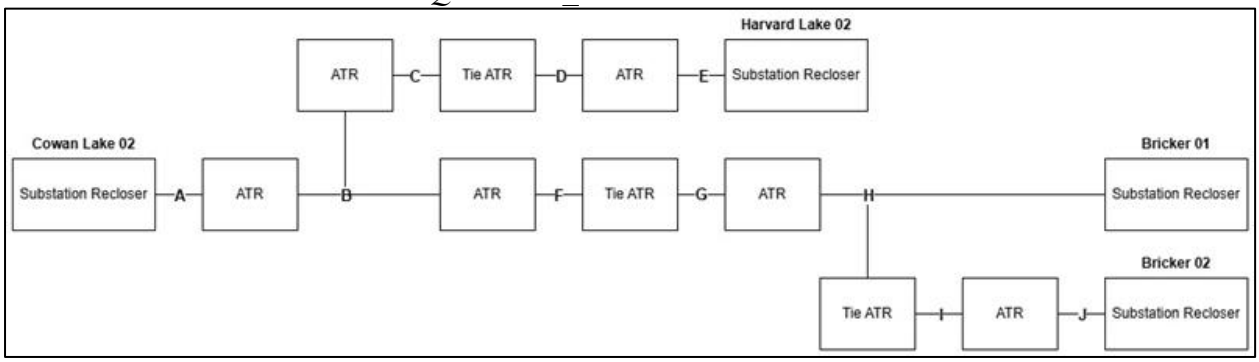


FIGURE 5
NORTH KENT HQ: COWAN_LAKE-1 FLISR NETWORK ONE LINE



Q. What capabilities and benefits do you expect FLISR to provide?

A. A FLISR network is designed to provide multiple capabilities including fault detection, fault location prediction, fault isolation, and service restoration. It does this by analyzing data from ATR/reclosers, line sensors, and other remotely communicating devices that are overlaid on an electronic map within ADMS. The FLISR application is controlled through ADMS's central logic. This centralized logic provides next generation switching automation through FLISR by analyzing the real-time operating model and the telemetered grid devices that exist within it, to provide automatic switching solutions that restore power to customers.

These switching solutions are superior to existing automatic restoration historically provided by ATR Loops in that they can handle real-time, dynamic scenarios depending on the current topography of the circuits involved and the active electric loading present on the system. These capabilities lead to greatly increased benefits to reliability in two main ways. First, the dynamic automation solutions from FLISR reflect the real situation on the grid unlike ATR Loops which have to assume the worst-case electric loading scenario when programmed for deployment. This means that FLISR can now unlock transfers if line capacity is available at times when ATR Loops would have assumed a

transfer was unavailable (like during hot summer months), thus leveraging any existing capacity out of the grid. Second, having a dynamic automation solution which can handle complex networks with multiple ties and numerous circuits enables the installation of more ATRs in places that were previously unable to handle the increased penetration due to device congestion and operational complexity. Considering the DA effort described above, enabling FLISR is the gateway to putting all those future devices to work for the maximum reliability benefit across the system.

As stated above in my testimony about DA, FLISR goes hand in hand with any and all devices and systems to automate the grid as planned in the ongoing DA deployment projection. Bringing FLISR fully online for mass integration with existing devices and with new devices brings the Company up to an industry best practice. Strategically substituting ATRs with FLISR Networks allows the larger DA program to deliver greater benefits for customers.

Another benefit of the program is its impact on safety. FLISR provides automatic isolation of faulted zones, which in turn decreases the safety risk of the public contacting energized downed wires. Since FLISR devices are telemetered, potentially downed wires can be automatically secured during blue sky days and storms. This directly supports MPSC Rule R 460.723 within the Service Quality and Reliability Standards for Electric Distribution Systems. Further, FLISR does this more safely than existing loop schemes since it does not need to use closing into faults as the method for isolating the faulted line from both sides, and instead can open and close to isolate based on known fault location in the overall system model. Another safety benefit is reducing hazard exposure of line crews

since these devices can be remotely operated, and thus maintenance functions like test operating can be automatically performed as routines without traveling to each site.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the FLISR investment category?

A. The Company is not projecting any capital expenditures on FLISR within the bridge or test years because the DA program is the umbrella program that will now account for this investment, mainly the field devices. The DA program will take over with additional deployment of ATRs/reclosers and switches to be controlled by FLISR.

Q. How will the FLISR project support the key objectives of the Reliability Roadmap?

A. The Company expects FLISR along with its DA program to be a flagship program that establishes a path to a more reliable electric distribution system. FLISR is poised to improve the management of electric outages by minimizing their impact and duration to customers. This project will automatically re-route power to limit the impact of outages. DA powered by FLISR will both shorten outages through quicker fault detection and location, as well as eliminate outages by isolating issues to the smallest area possible.

Voltage Regulator Controllers

Q. Please summarize the capabilities and objectives of the Voltage Regulator Controllers project.

A. Voltage regulators adjust voltage on the electric distribution system based on changing load conditions to ensure customers receive energy delivered within tariff-specified limits, as indicated in MPSC R 460.3702 (Rule 702). Voltage regulators are remotely connected through the ADMS via a communications-enabled controller, and provide dynamic remote-control and monitoring capabilities for increased visibility for the Company into

the electric distribution system. An example of an upgraded voltage regulator controller is shown in Figure 6.

FIGURE 6
VOLTAGE REGULATOR CONTROLLER



Q. Has the Company performed a BCA on Voltage Regulator Controllers?

A. Yes. Please see Exhibit A-160 (SAM-3), which also contains a revenue recovery calculation. Voltage regulators benefit customers by improving power quality and efficient energy delivery for customers impacted. The dynamic capabilities of the voltage regulator controllers support voltage efficiencies gained through the implementation of Conservation Voltage Reduction ("CVR") and Volt-VAR Optimization ("VVO"). Through the installation of a modem and antenna in the voltage regulator controller, the Company can generate additional MWh savings with this improved visibility and control, as supported by the DOE report titled *Application of Automated Controls for Voltage and Reactive Power Management*, published in 2012[5].

[5] Office of Electricity Delivery & Energy Reliability. (2012). *Application of Automated Controls for Voltage and Reactive Power Management.* U.S. Department of Energy. energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf

One of the many benefits of voltage regulator controller deployment is as an enabler of the CVR program, which achieves reduction of energy consumption and peak demand on the electric distribution system. The CVR program and the benefits it provides are discussed in more detail in the direct testimony of Company witness Partlan, as well as the Company's 2021 Integrated Resource Plan ("IRP") in Case No. U-21090, which was settled and approved by the Commission in 2022. Beyond CVR, voltage regulators can be remotely controlled through the DA program described previously to provide voltage support in complex FLISR networks allowing more transfer opportunities while still providing acceptable voltage to customers.

The two-way communication capability also avoids costs by enabling preventative maintenance and proactive replacement of units approaching end-of-life. Proactively replacing equipment prior to failure can prevent customer outages and improve reliability.

The preventative maintenance features also result in the life extension of voltage regulators, further reducing costs. This remote monitoring capability also eliminates the need to perform manual calendar-based inspections, a more costly and timely maintenance method, thus eliminating the need to deploy field crews, which aligns with the DOE's report. By incorporating the ability to remotely monitor and control the voltage regulators with the installation of the modem, the Company saves on cellular costs due to the number of modems, on average, being reduced per location. Most locations only require one modem per voltage regulator controller in lieu of one modem per phase per location because the multiphase controller only requires one modem regardless of how many phases are at the location. The execution of this program has resulted in avoided costs due to the replacement of both failed and older vintage materials with newer, more efficient materials,

thus avoiding the emergent replacement of materials and the potential adverse effects on customer voltage levels.

Finally, this investment benefits the Company's electric line workers through reduced exposure to electrical and traffic hazards. Often these locations are on the side of a roadway, requiring electric line workers to establish a safe work zone. This ability to remotely monitor and operate improves the safety of the Company's workforce.

Q. What is the Company's long-term plan for deployment of Voltage Regulator Controllers?

A. The Company plans to upgrade 232 voltage regulator locations in 2026 as the final year of deployment for this program. As of March 31, 59 locations or 25% of the project plan had been completed in the first quarter.

Q. Please identify the projects that will be accomplished with the requested spending level in the Voltage Regulator Controller investment category.

A. The Company has identified projects for the bridge period, and they are listed in Exhibit A-161 (SAM-4). Additionally, an inventoried list of voltage regulator controllers as to what is to be installed is included in Exhibit A-162 (SAM-5) per the Commission requirement in Case No. U-21870. On April 1, 2026, the Company completed an inventory assessment of the number of Line Regulator Controls available to complete the final year of Deployment. The assessment confirmed that the existing inventory is sufficient to complete the planned scope of work, including a limited contingency to address normal course deployment needs, such as emergent failures at voltage regulator locations requiring controller replacement to restore full functionality.

Q. What is the Company's projected bridge period year spending level, for which it is requesting cost recovery, for the Voltage Regulator Controllers investment category?

A. The Company is projecting Voltage Regulator Controller capital expenditures of $6,276,352 in the bridge period.

Q. How did the Company develop its projected costs for Voltage Regulator Controller expenditures?

A. The unit cost for a regulator location is estimated based on material and labor costs associated with the number of phases, and existing health of the location. This is typically driven by three key components:

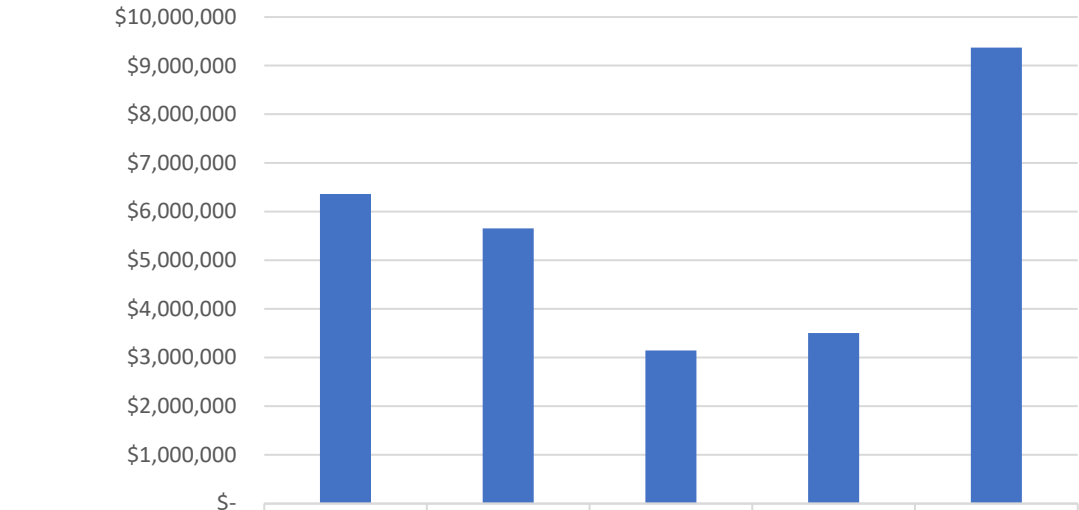
- Voltage Regulator Controller & Communication Hardware – this consists of either a multi-phase control, or one to three single phase controls that allow the remote monitoring and control of the regulators as well as modem(s) and antenna(s);
- Voltage Regulator Pole Top Hardware – based on an inspection, the estimated number of tanks and other equipment that require replacement to gain full functionality at that location; and
- Labor Unit Costs are negotiated with the responsible Construction Contractor, and each major work scope component is assigned an individual Unit Cost to more effectively manage, monitor, and control labor costs associated with the construction aspects of the project.

The cost for each work order is the sum of the labor and material costs of each location included in the work order. The cost of the investment category is a sum of the cost of all the work orders.

Q. What has been the historical actual spending for the Voltage Regulator Controllers category for the past five calendar years?

A. The Company's historical actual spending in the Voltage Regulator Controllers investment category for the past five calendar years is shown below in Figure 7.

FIGURE 7
VOLTAGE REGULATOR CONTROLLER 5-YEAR HISTORICAL SPENDING & INSTALLATIONS COMPLETED



	2021	2022	2023	2024	2025
Voltage Regulator Controller Deployment	$6,358,823	$5,654,047	$3,143,732	$3,501,251	$9,369,559
# of Locations Installed	162	367	160	156	205

Q. Please explain year-over-year variation in spending in this investment category.

A. From 2021-2025, the five-year average spending for this investment category is $5.61 million. Variance between years during this period can be attributed to variance in the number of planned locations for each year as well as instances where material is purchased the year before the planned deployment to ensure the most efficient installation and use of available labor resources during the first few months of the following year. While Figure 7 shows a large increase in 2025, the overall average unit cost for the 2026 voltage regulator locations has decreased relative to the previous year of 2025. To explain, voltage regulator controllers were purchased late in the year 2025 to support the 2026 deployment year. This equated to $3.15 million. Subtracting $3.15 million from the $9.37 million shown in Figure 7 equals $6.22 million, more in line with previous years. Doing so did not only avoid inflationary cost increases for these critical components, but also facilitated the start of construction deployment activities early in 2026. Inflationary

pressures, especially as they relate to materials, have been an additional factor in this variance from year to year. The Company conducted a competitive bidding process with respect to Construction Labor for the later years of the project, including 2025 and 2026. As a result of this process the Company has identified potential cost savings of about $1.5 million with respect to Construction Labor activities related to the project for the later years. The potential savings of about $3,400 per unit for each location has already been incorporated into the funding request.

Q. Does average unit cost as calculated in Exhibit A-96 (EMD-12) reflect the expected spend per project for this investment category?

A. No. Project costs in this investment category occasionally encompass more than just the subject calendar year. Material for this investment is purchased in larger batches, typically several months before the planned installation, to account for procurement long lead times and to ensure material availability for the crews prior to the start of deployment. This allows the project to use dedicated crews with a full complement of material availability. The investment category has seen significant efficiencies and reduced costs using this method of construction. In some years crews are allocated to start this project near or in the first quarter of the year, requiring a significant amount of material be purchased the calendar year before. In other years, deployment is started later in the year and the material is purchased in the same calendar year as the construction. This shift in timing could result in paying for two years of material in one calendar year, and a relatively minimal amount of material the following year. The material for this project accounts for about 50% of the cost, and therefore the method of taking the annual cost and dividing it by the annual units completed is not an effective method of understanding the unit cost. Using a blended

approach of considering total units and costs over multiple years, levels the unit cost and accounts for the variations described above. Unit costs are calculated based on historical data, contracted labor, and material cost across all projects in the investment category without considering calendar year spend. In Case No. U-21870 Order, at page 113, the Commission found that a unit cost approach is not appropriate for this program.

Q. How will the projected Voltage Regulator Controller expenditures support the key objectives of the Reliability Roadmap?

A. The Company is seeking to improve the efficiency of the electric distribution system by leveraging proven grid technologies, which includes voltage regulator controllers. This investment category is a primary component to enable the Company's CVR plans that have been highlighted in the Company's 2021 IRP. The Voltage Regulator Controller deployment project deploys grid communication equipment, which provides increased visibility into the electric distribution system resulting in improved reliability for customers and serves as a central part of the Grid Automation investment plan. In September 2023, Liberty completed their audit of the Company, associated with Case No. U-21305, with a review of the Company's Reliability Roadmap. In the Liberty Report Part II, page 87, number 24, it was concluded that "The voltage regulators the EDIIP proposes are sound." Liberty's conclusion that the "expenditures are moderate and in line with what one can expect for a system like that of Consumers" supports the need for the investment described in my testimony.

Metro Modernization

Q. Please summarize the objectives of the Metro Modernization project.

A. The Company's Metro system provides necessary power to many downtown urban areas through a network of underground vaults. Company witness Kurt K. LaFrance provides a more detailed explanation of this critical infrastructure. The Metro Modernization project is part of the overall DA program, discussed previously. Improved customer reliability, operational cost savings, and Metro integration into ADMS require asset upgrades similar to devices and systems that are currently deployed on the overhead electric distribution system. In pursuit of this, the project will build the standard that will use sensors designed to detect water or gas hazards within the Metro system, switching equipment to support DA allowing for remote-control capabilities in Metro operations.

Q. What capabilities and benefits do you expect the Metro Modernization project to provide?

A. Bringing vaults to a new standard that includes communication and sensing solutions enables safer and more effective operations. This project supports situational awareness by introducing monitoring and control capabilities into metro vaults, which reduces operational costs via remote operation with easier maintenance of switching equipment, similar to what is used on the LVD/high voltage distribution ("HVD") electric distribution system. Added visibility to equipment health enables proactive maintenance and inspection prior to larger failures and would lead to a further reduction in costs. This project also supports reliability by significantly speeding up operations and outage restoration, providing shorter outages for customers. Projected benefits are shown in Exhibit A-163 (SAM-6) reporting avoided CMI, which also contains a revenue recovery

calculation; while the CMI component may seem small, the Metro system hosts a disproportionately larger percentage of commercial and priority customers such that reducing otherwise exceedingly long outages on the Metro system significantly impacts the customer experience. Further, there is a meaningful reduction in annual work hours totaling 185 hours of exposure to dangerous confined spaces to electric line workers when all vaults become upgraded in the future. A tragic incident involving an AEP utility worker in Texas is a reminder just how dangerous the confined spaces like the Company's Metro system can become. An article described how "[t]his incident serves as a somber reminder of the hazards involved in maintaining critical infrastructure, particularly in confined underground spaces where electrical risks can be heightened[6]." While safety incidents in underground Metro electrical systems are rare, they can be extremely dangerous if they do happen[7]. Violent explosions can occur at any time, thus necessitating the need to monitor this underground equipment. The improved safety benefit for Company electric line workers and the public alone necessitates this investment.

Q. How are Metro Modernization locations selected and prioritized to maximize customer benefit?

A. This project will target two vaults to upgrade initially. These sites will be chosen based on use cases of site types typical of the Metro system. The use case that will drive site selection include sites of operational importance to receive upgraded switching devices and a method to communicate back to the Control Room through SCADA. This is the same technology used on the overhead/above ground electric distribution system today. Adding

[6] https://www.kristv.com/news/local-news/in-your-neighborhood/corpus-christi/the-utility-worker-who-died-of-apparent-electrocution-in-a-manhole-is-identified-as-an-aep-texas-employee
[7] Boston Manhole Explosions Injure 1, Force Evacuations – NBC Boston - https://www.nbcboston.com/news/local/multiple-manhole-fires-reported-in-boston/2737181/

communications to the metro system brings these underground systems in line with the Company's overhead grid. These sites are also well positioned for future capabilities to include flooding and/or gas leaks environmental detection sensors that will improve electric line worker safety. It is also of note that many of the Metro systems statewide all serve high-scoring EJ communities such that all Metro investments associated with this project and future deployments will be providing a positive impact for those communities.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the Metro Modernization investment category?

A. The Company is projecting Metro Modernization capital expenditures of $305,000 in the bridge period and $650,000 in the test year. The requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology. Future expenditures will be covered as part of the DA program discussed previously as the objective is to bring the same capabilities used on the overhead/above ground distribution system to the underground metro system.

Q. How will the projected Metro Modernization expenditures support the key objectives of the Reliability Roadmap?

A. Providing visibility and remote-control access to Metro vaults will yield valuable operational capabilities to improve reliability. Metro Modernization will introduce additional switching devices, brought to a new standard, with communication. Enhanced remote and local control options will speed operations and restoration. The monitoring of devices and hazard sensors also can contribute to proactively addressing issues before they lead to catastrophic failures, thus avoiding unnecessary equipment failure outages. Finally,

introducing smart and communicating equipment in vaults sets the stage for future DA schemes involving the Metro system, and integration with FLISR and ADMS switching solutions—all of which positively affect reliability of the Metro system.

IP-Enabled Remote Terminal Unit

Q. Please summarize the objectives of the Internet Protocol ("IP")-Enabled Remote Terminal Unit ("RTU") project.

A. The objective of the IP-Enabled RTU project is to overcome the limitations associated with the existing serial-based RTU hardware and network design used by the Company by enabling IP communications and integrating Field Area Network ("FAN") equipment. Currently, the RTU faces technical challenges such as (1) remote monitoring and management (i.e. the inability to monitor, manage, and maintain the RTU remotely impacting both cybersecurity and day-to-day operations), and (2) design complexity (i.e. existing design limitations necessitating additional wiring for collecting substation data, leading to increased cost and complexity). Serial technology is now becoming increasingly obsolete and the industry is moving away from supporting that communication standard to Intelligent Electronic Devices ("IEDs"). Previously, the Company had to address and upgrade modem standards during the 3G sunset, and it is only a matter of time before serial technology also becomes unsupported in the industry and severely limiting technology options to better serve customers. To address these issues, the project has introduced hardware and configuration changes that have undergone rigorous testing in a controlled lab environment. These tests covered operational functionality, cybersecurity, interoperability, and engineering functionality.

Q. What capabilities and benefits do you expect the IP-Enabled RTU project to provide?

A. The IP-Enabled RTU project will bring digital communications to the substation, setting up the framework for the IP-Enabled IEDs and Common Substation Platform. These units enable the delivery of the following capabilities for upgrading distribution substations:

- Data Network Security
- Improved Operator Efficiency
- Enhanced Situational Awareness
- Standards Based Designs and Data Communications
- Remote Engineering Access
- Configuration & Firmware Management

Ultimately, not pursuing this enhancement will leave critical substation communications infrastructure stuck with antiquated serial protocols that will lead to increased incompatibilities with modern hardware, and a potentially costly and/or urgent need to update on a less convenient and more aggressive schedule if establishing this deployment is deferred. These protocols have reached end of life and require an upgrade to industry standard IP enablement. A safety benefit is the reduced electrical exposure at high voltages for the Company's front-line work force. Today, electric substation workers must enter into the substation fencing to perform their tasks of updating firmware and adjust settings. Remote Engineering Access through this device will eliminate the need to perform those tasks onsite.

Q. How are IP-Enabled RTU locations selected and prioritized to maximize customer benefit?

A. The initial deployment locations were selected to confirm the capabilities described above and to be locally accessible to the resource groups in Jackson, MI. These locations represent distribution substations with a current standard RTU that supports remote engineering, automated monitoring, and cyber security requirements. Additional consideration was given to locations where the SCADA cabinet included ample space for the additional FAN communications equipment.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the IP-Enabled RTU investment category?

A. The Company is projecting IP-Enabled RTU capital expenditures of $190,000 in the bridge period. It is important to note the requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology. Future expenditures will be covered as part of the DA program discussed previously.

Q. How will the projected IP-Enabled RTU expenditures support the key objectives of the Reliability Roadmap?

A. IP-Enabled RTUs are the first foundational technology enhancement to substations that will be built upon in the coming years. Once fully realized, the capabilities of the substation of the future will provide benefits to many areas including reliability, grid security, and safety. As the devices on the electric distribution system become smarter and more interconnected, it is crucial that distribution substations keep up with that trend and can be an important part of the integrated solutions to come. This project is a critical first step to achieving that capability.

IP-Enabled IED

Q. Please summarize the objectives of the IP-Enabled IED project.

A. The objective of the IP-Enabled IED project is to overcome limitations associated with the existing hardware and network design of additional IEDs.

An IED can include regulators, reclosers, and transformer bank monitoring equipment. These IEDs currently lack the capability to connect and communicate over IP networks, which hinders their integration into the FAN. This project will deploy new hardware into the substation allowing the communication of IEDs back into the Control Room and across Engineering departments.

Q. What capabilities and benefits do you expect the IP-Enabled IED project to provide?

A. This project builds on the infrastructure set up in the IP-Enabled RTU project. There are additional data points and logs available within the substation devices that cannot be pulled remotely now or even through an upgraded RTU.

A major benefit to IP-enabled IEDs is that retrieval of this information will be instantaneous and avoids the cost and risk of dispatching an electric substation worker to the substation site to download the information, reducing truck rolls and improving coworker safety. Similar to IP-Enabled RTUs, a safety benefit is the reduced electrical exposure at high voltages for the Company's front-line work force. Today, Utility Workers must enter the substation to perform their tasks of pulling log data. With a FAN established, as detailed in the IP-Enabled RTU section, Remote Engineering Access is available. This will eliminate the need to perform those tasks onsite.

Q. How are IP-Enabled IED locations selected and prioritized to maximize customer benefit?

A. The IP-Enabled IED project plans to use existing IP-Enabled RTU locations. This approach provides the Company with the opportunity to integrate learnings from both projects and demonstrate use case capabilities and continuity. These locations represent a large (six distribution circuit) and a smaller (two distribution circuit) substation with multiple current standard control types that will support remote engineering, automated monitoring, and cyber security requirements.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the IP-Enabled IED investment category?

A. The Company is projecting IP-Enabled IED capital expenditures of $280,000 in the bridge period. It is important to note the requested investment in the bridge and test period are not for a full system-wide deployment, but only the initial implementation of this technology. Future expenditures will be covered as part of the DA program discussed previously.

Q. How will the projected IP-Enabled IED expenditures support the key objectives of the Reliability Roadmap?

A. This project will provide immediate access to logs, event data, and other detailed information concerning substation equipment to enable predictive failure analysis. The ability to perform analysis in real-time based on data across key substation equipment will enable the identification of imminent failures or the need for repairs *before* an outage occurs. It also enables faster diagnosis into the reason for failures during an outage. Both will reduce or eliminate outages related to substation equipment, and will reduce costs and large-scale customer outages that stem from emergent repairs.

V. Planning Systems Modernization

Q. Please describe the Planning Systems Modernization Initiative.

A. The Planning Systems Modernization initiative is dedicated to evaluating, developing, and implementing desired future state technologies and solutions to integrate into the Company's planning framework. This initiative takes a comprehensive and holistic view of the electric business's planning steps and processes to assess improvement opportunities and recognize future state requirements. The Planning Systems Modernization initiative is intended to leverage advancements in technology to develop enhanced datasets that improve the performance and granularity of planning tools; enable additional functionality to address evolving business needs, including the integration of distributed energy resources (DER) and electrification; and account for interdependencies with other Company initiatives to support cross-functional use cases. Currently the Planning Systems Modernization initiative is comprised of a forecasting tool implementation and a technology upgrade to the existing Load Flow Tool necessary to maintain regulatory compliance and to conduct accurate grid modeling.

Q. Are there any changes to the structure of Planning Systems Modernization from what was discussed in prior Case Nos. U-21585 and U-21870?

A. Yes. To better represent the current and future scope of this investment category, the Company has consolidated what was previously referred to as the Load Flow Tool Upgrade into the broader Planning Systems Modernization initiative. While the capabilities, investments and scope of work associated with the Load Flow Tool Upgrade remain unchanged, the former name unintentionally implied a narrow focus on enhancements to a single load flow application (i.e. CYME). In practice, this work is part of a more

comprehensive, multi-faceted effort to deploy the next generation of planning capabilities both within and alongside the existing CYME implementation. Planning systems Modernization more accurately reflects the breadth and intent of the initiative.

Q. Please summarize the objectives of the Planning Systems Modernization Initiative.

A. Planning Systems Modernization seeks to advance the Company's planning processes and tools by developing new functionalities within and alongside the CYME power engineering software, which has been a cornerstone for many utility planning departments for nearly 25 years. The current planning tool implementation requires an overhaul to enable the Company to remain capable of proactively addressing the evolving challenges and opportunities associated with increasing DER penetration and electrification on the distribution system. It is also required to meet regulatory expectations related to the fast track initial and supplemental DER review screens, Michigan Transportation Electrification Plan, hosting capacity map enhancements, increase in the Distributed Generation program cap, and Distribution System Plan ("DSP") reporting requirements introduced in Case No. U-20147

Key components of Planning Systems Modernization include, but are not limited to:

- Selection and implementation of an industry standard forecasting tool capable of producing hourly, weather normalized load forecasts under alternate future DER, load growth, and economic scenarios;
- CYME Gateway and underlying data model enhancements to improve modeling of sources, group regulated circuits, and the secondary system in as-built and as-planned network models;
- Leveraging CYME's Advanced Project Manager module and as-planned network model to enhance collaboration, communication, and prioritization of distribution system upgrades across a long-term planning horizon;

- Enabling time-series load flow simulations in the CYME software using historical Advanced Metering Infrastructure ("AMI"), MV90, and SCADA data or the forecasted load data above through integration with the forecasting tool;

- CYME Gateway and underlying data model enhancements to automate the import of existing DER interconnections into the CYME as-built network models;

- Integration with PowerClerk and/or SAP to include queued but not yet commissioned DER interconnection requests in the as-planned network model at a future point in time;

- Integration with other enterprise systems to include detailed project scope, milestones and costs into the CYME as-planned network models at a future point in time;

- Development of automated solutions to enable comprehensive review of the fast track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards; and

- Enhancements to the Company's future load and generation hosting capacity maps recommended by the MPSC's September 8, 2022 Order in Case No. U-20147; the Distribution System Data Access workgroup and June 30, 2023 Grid Integration Study filed in Case No-21251; March 1, 2024 Order in Case No. U-21389; and July 10, 2025 Order in Case No. U-20147.

Q. What progress was made in 2025 on Planning Systems Modernization?

A. In 2025, the Company advanced its Planning Systems Modernization efforts by completing the CYME Advanced Distribution Planning System Discovery project in June. At a high-level, the workshops and final findings of this effort identified project scope, data requirements, estimated costs, and an initial implementation timeline. One key conclusion was that selecting and deploying a forecasting tool is a critical first step before pursuing broader data integration and automation activities. The forecasting tool will serve as the source of planning model data for future time-series datasets, as well as cleansed, historical time-series datasets from AMI, MV90, and Distribution SCADA ("DSCADA"). Establishing this architecture early avoids development of costly integrations into multiple

enterprise systems for historical data, that would later need to be overhauled when the forecasting tool implementation was complete. Based on this finding and other emerging regulatory requirements for distribution system forecasting established by the Commission's June 2025 Order in Case No. U-20147, the Company selected and procured licensing for the LoadSEER forecasting application by Integral Analytics in Q4 2025.

In parallel with the efforts described above, the Company developed temporary in-house scripting that enables partial automation of many MIXDG Fast-Track and Supplemental screens for Levels 1–3 generator interconnections, that were adopted by the Commission in Case No. U-20890. Beginning in 2026, these screens will be required for any new interconnection applications on circuits exhibiting symptoms of DER oversaturation, including but not limited to overvoltage and inverter tripping.

The Company also developed an AMI-based report to identify circuits where existing DERs are, or soon will be, causing primary or secondary voltage rise beyond acceptable limits. These circuits will be prioritized for initial implementation of the screening requirements.

The interim approach serves as a bridge solution to safeguard customers and maintain grid integrity from adverse DER impacts. It will remain in place until a fully mature and robust DER Screening solution is delivered through ongoing strategic investment in the Planning Systems Modernization initiative.

Q. What are the next phases of Planning Systems Modernization, and what capabilities and benefits will they provide?

A. The next phases of Planning Systems Modernization include a series of foundational IT, data, and planning tool enhancements that will modernize the Company's forecasting and

distribution planning capabilities. Beginning in 2026, the Company has begun the work to stand up the required IT architecture and initiate a phased implementation of the LoadSEER forecasting tool, with mature historical and forecasted datasets expected to be ready for integration with planning tools in 2027. During this period, the Company will also begin the data integration and enhancement phase of the project, which includes a series of Gateway change requests and underlying data model improvements to strengthen source -to -circuit connectivity, substation transformer, group regulated network and DER modeling within planning tools. In parallel, the Company will build the IT architecture needed to support time-series modeling, long-range scenario planning, and the implementation of CYME's Advanced Project Manager module. This phase will require the purchase of new software and server technology licenses that will establish a modernized framework and data model to support future automation phases.

These upgrades are necessary because the Company's current planning tools rely on static, single-point-in-time load models that historically met the needs of distribution planners but can no longer capture the dynamic and intermittent load shapes introduced by Electric Vehicles ("EVs"), rooftop solar, batteries, heat pumps, and other emerging technologies. Evolving technologies and their related impacts on the grid require planning simulations to be performed in the time domain, which in turn requires integrating AMI, MV90, and DSCADA datasets with planning models. Time-series datasets from various device types and head-end systems require pre-processing prior to import to ensure that interval formats are aligned and abnormal data or system configurations are omitted. Even then, these datasets are representative of historical operating conditions which are becoming a less reliable indicator of future system behavior. Without investment in

planning systems, the Company's ability to identify issues emerging on the LVD system will be inhibited as customer technology adoption accelerates.

Planning Systems Modernization will first address these limitations through the LoadSEER implementation, which will provide a single source of validated, production-ready timeseries data that seamlessly integrates with planning tools. LoadSEER will support the pre-processing and staging of historical data from multiple enterprise systems and will enable the development and maintenance of hourly, weather-normalized circuit-level forecasts extending one or more decades into the future under varying customer adoption, climate, and economic scenarios. These enhanced capabilities will allow the Company to proactively identify constraints, optimize investment decisions, and transition to a modern, forward-looking planning framework aligned with industry best practices and regulatory expectations, including those required for future DSPs under the Commission's June 2025 Order in Case No. U20147.

Through the implementation of CYME's Advanced Project Manager module, the project will also provide cross-departmental visibility into distribution system enhancements being evaluated by Company departments such as: LVD Circuit Planning, Substation Planning, System Protection, Metro Planning, Grid Automation, and Distribution System Operations within a unified, as-planned network database. This integrated architecture will reduce the need for manual sharing of individual CYME studies and ensure that traditional infrastructure upgrades and non-wires alternatives are coordinated to maximize customer value. As the forecasting tool and Advanced Project Manager implementations mature, Planning Systems Modernization will transition to

building the interface between the planning tool and forecasting tool to enable time-series simulation in CYME.

Integrating historical and forecasted time-series datasets with planning tools will provide:

- significantly increased model accuracy and precision;
- reduced model development time through enhanced load allocation;
- proactive mitigation of voltage anomalies resulting in a reduction of customer complaints;
- faster resolution of customer complaints when they occur;
- visibility into present and future time-based impacts of DERs, electrification, and demand response under alternative customer adoption, behavior, and weather scenarios;
- insight into the duration and frequency of equipment overloads to assess deterioration and emergent failure risk, reducing overload-related outages (as discussed in the LVD Overload Risk Reduction section of the Reliability Roadmap);
- simulated evaluation of non-wire alternatives ("NWAs"), virtual power plants ("VPPs"), and flexibility programs; and
- identification of system constraints and optimization opportunities at any hour of the year.

Several aspects of Planning Systems Modernization are required for the Company to maintain regulatory compliance now and in the future. At maturity, this effort will enable a comprehensive review of the fast-track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards and will pursue full automation of these screens where technically feasible. It will also support ongoing advancements to the Company's hosting capacity maps as discussed in the Reliability Roadmap. In addition, Planning Systems Modernization is required to complete the distribution system impact analysis and data reporting

requirements of the Michigan Transportation Electrification Plan, will provide planning and interconnection engineers with the insights needed to manage the increased Distributed Generation program cap implemented by PA 235, and will allow the Company to maintain compliance with DSP reporting requirements introduced in Case No. U-20147.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the Planning Systems Modernization investment category?

A. The Company is projecting Planning Systems Modernization capital expenditures of $3,970,000 in the bridge period and $2,841,000 in the test year.

Q. How will the projected expenditures support the key objectives and regulatory requirements of the Reliability Roadmap?

A. Planning Systems Modernization will enable the Company to comply with the Commission's July 10, 2025 Order in Case No. U-20147, which established new requirements for electric utility DSPs. Specifically, the *Load Forecasts, Scenario Planning, and DER Outlook* section on page 7 and the *Grid Modernization Efforts* section on page 8 of Appendix A introduced expanded expectations for load forecasting, scenario planning, and the consideration of DERs, EV adoption, demand response, and related technologies. These requirements will be met through the Company's 2026 LoadSEER implementation and subsequent integration and enhancement of the CYME planning tool.

In addition, enabling time-series simulation capabilities in CYME will allow planners to evaluate the duration and frequency of potential device overloads to quantify whether deterioration, and eventual emergent failure, are likely to occur. See the *LVD Overload Risk Reduction* section of the Reliability Roadmap in Company witness Duke's

testimony for further discussion on this topic. In addition to evaluating overloads, time-series power flows in planning tools will allow planners to proactively identify and mitigate voltage issues before they occur.

Planning Systems Modernization seeks to advance the accuracy, granularity, and frequency of updates to the Company's hosting capacity maps. The project will explore hosting capacity process automation using either Electric Power Research Institute ("EPRI") DRIVE or CYME's Integrative Capacity Analysis module. For further discussion, see the Hosting Capacity Section in the Reliability Roadmap.

DER Optimization

Q. Please summarize the objectives of the DER Optimization Initiative.

A. DER Optimization seeks to develop a standardized methodology for delivering important capabilities, including but not limited to the modeling, monitoring, operating, and coordinating needed to optimize and safely integrate DER into the electric distribution system. This approach includes research, planning, and development of hardware and software projects to evaluate DER management capabilities across the spectrum of DER types through the implementation of a DER Management System ("DERMS"). The Company defines DERMS as an enterprise scale software platform that is located at the utility's operational center. While broader applications such as edge DERMS, fleet DERMS, Aggregator DERMS and VPPs are not explicitly included in this definition, it is important to note that they will be considered in the scope of the DER Optimization program.

Q. How is the Company planning to proceed with the DER Optimization initiative?

A. The Company plans to initiate a workgroup with interested stakeholders by the third quarter of 2026. Some of the objectives of this workgroup are: listen/learn the best approaches to

integrate DERs into the Company's operations, benchmark other states on program design, determine how VPPs can be incorporated and outline an appropriate path forward for a business case. This aligns with the Commission's recommendation in their Order in Case No. U-21585, which said:

> The Commission encourages the company to initiate a workgroup with interested persons and to develop more pilots or other actionable proposals to develop and further evolve the company's initial proposal.

In addition, to this workgroup, the Company will also continue to actively participate in EPRI's DER Integration program and other industry workgroups to both maintain and increase awareness of emerging best practices for DERMS implementations and valuing the benefits of DERs in other states. The Company will remain engaged in the Benefit-Cost Analysis Tool Collaborative as part of Case No. U-20898 and apply this work to the development of a BCA.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, for the DER Optimization investment category?

A. The Company is not requesting funding in this case. Instead, the Company will establish a workgroup with the aim of bringing stakeholders together to address the items raised in Case Nos. U-21585 and U-21870.

VI. Electric Distribution Asset Management

Q. Please summarize the objectives of the Electric Distribution Asset Management ("DistAM") Initiative.

A. DistAM is the application of asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle, resulting in improved reliability through reduced equipment failure.

DistAM will develop lifecycle management capabilities by collecting key asset data (e.g. age, nameplate data, location, work orders) to drive a risk-informed, value-based decision-making methodology to manage and optimize asset investments. The components within DistAM will collect distribution asset data into a single centralized database that provides enhanced integration into asset health performance analysis, and investment strategy platforms.

Key objectives within DistAM are to improve the Company's capital efficiency and asset maturity levels. With increased asset maturity the Company will leverage advanced risk analytics to create asset health scores, essential for optimizing investment planning scenarios, and addressing outages before they happen. This work is aligned with industry best practices defined in ISO 55000(1), as well as from the Michigan Infrastructure Council Asset Management Program.

Q. Please describe the DistAM Approach.

A. The Company developed a DistAM strategy with key workstreams: Asset Repository ("AR"), Asset Performance Management ("APM"), and Asset Investment Planning ("AIP") (now complete).

Utilities without a structured asset management approach still accomplish ad hoc and reactive asset management tasks; however, this stopgap approach will not provide the same customer benefits and desired system performance. Rather, it will continue to drive increased system costs based on the lack of capability for data-driven decisions and planning.

DistAM is distinct from ADMS because it focuses on the lifecycle asset management rather than real-time operational management of assets. Asset management

typically requires data that is collected and visualized over long-time scales. Consequently, DistAM informs decisions over the medium-to-long term as opposed to ADMS's short-term operational decision-making.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures of $1,850,000 for the bridge period and $1,080,000 for test year for Asset Repository.

Q. How much has the Company invested in the DistAM program to date?

A. Since the launch of DistAM, the Company has invested $11.8 million as of March 31,2026. The AIP was launched in 2024 and consisted of $5.9 million. Since the launch of this project, $5.9 million has been spent on the AR and nothing has been spent on the APM as of March 31, 2026. The Commission originally approved the DistAM project in Case No. U-20697 and reapproved in the December 22, 2021 Order in Case No. U-20963. The concept approval at the time projected an estimated $12 million for the project. This is the amount the Commission discussed in its Case No. U-21585 Order, stating the approval of increased costs would require updated data. Furthermore, the Commission supported the investment into the AR but disallowed APM in Case No. U-21870. Based on the Commission's order in Case No. U-21870, the Company is not seeking recovery of the APM in this case.

Q. How much is the Company proposing to spend on the DistAM program through the test year in this case?

A. Including the prior investment through the test year, the Company's current total projected spend for the DistAM program is $14.7 million.

Q. Why is the Company not seeking recovery of APM in this case?

A. Based on the Commission's Order in Case No. U-21870 the Company will focus on making more progress on the APM solution and seek recovery in a future rate case.

Asset Repository

Q. Please summarize the objectives of the AR.

A. The AR provides a single, centralized database to store essential distribution asset data. The AR identifies and structures asset relationships including asset grouping, parent-child relationships, and organization hierarchies. For example, it can identify the relationships between a voltage regulator, the voltage regulator controller, and the cellular modem so these three components can be evaluated (risk-assessed) together. Grouping related equipment drives cost efficiencies by ultimately allowing for the bundling of work at the same locations. Maintaining an AR facilitates sharing of asset information across multiple software, systems, and third-party applications. A major component of the implementation of an AR is the software and data integration. The AR provides the APM and the AIP tools a single source of truth for asset information eliminating redundancy and inaccuracy. Along with the software and data integration, the AR also has the objective to collect comprehensive and accurate data on major electric distribution assets. Drone flights and imaging have been added to collect comprehensive and accurate data on distribution assets.

Q. What capabilities and benefits do you expect the AR to provide?

A. DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed. The AR enhances the Company's asset life-cycle processes, data, imaging, and technology, allowing for improved capture and analysis of asset health details, which will

lead to more optimized investment planning scenarios. The primary benefits of DistAM include:

- Reduced capital and maintenance costs
- Reduced customer outages and restoration costs
- Reduced power quality issues and system losses
- Increased asset availability
- Reduced asset degradation risk
- Improved resilience of the electric distribution system
- Improved asset maturity
- Imaging

A centralized asset repository improves work efficiency by avoiding the need to manage across various software to pull and analyze data. In addition to improved efficiency, this tool provides the ability to complete advanced risk analytics to create asset health scores. The benefits of the AIP and APM would not be fully realized without a robust asset repository feeding consistent, comprehensive data. DistAM will use smart grid technologies to effectively coordinate the use of devices, the data they consume, and the information they produce, supporting all other Grid Automation capabilities in delivering benefits to customers.

A comprehensive BCA is provided for the DistAM as a whole in Exhibit A-164 (SAM-7), including all necessary components of AR, APM, and AIP, which also contains a revenue recovery calculation. It is important to note the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets. The requested investment in the bridge period and test year does not include the full system costs. Future

rate cases will request the needed funding to complete the full implementation of this technology. Exhibit A-164 (SAM-7) contains the estimated total costs across the life of the DistAM program.

Q. What electric distribution assets will be considered within the AR?

A. The AR will consider all major electric distribution assets on both the HVD system and LVD system. Examples of the assets that will be considered in the AR include:

- Equipment installed on the Company's HVD lines, including but not limited to poles, switches, insulators, and conductors;
- Equipment installed within distribution substations, including but not limited to transformers, regulators, reclosers, breakers, and relays; and
- Equipment installed downstream from the distribution substation fence, including but not limited to poles, conductors, transformers, capacitors, voltage regulators, metro equipment, and isolators.

Seven assets were added into the AR in 2025. Thirteen electric assets are planned to be included by the end of 2026 with a total of 19 assets planned for by the end of 2027.

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The AR is the foundational component of the broader DistAM strategy. To enhance the ability to proactively monitor and replace assets prior to creating an outage, the Company needs a system that tracks and structures the data in a methodical approach. The AR provides that standardization and is an enabler of the many beneficial reliability programs that follow, including AIP and APM. As covered in the Reliability Roadmap, the DistAM program is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed to increase reliability for customers.

VII. Weather Stations

Overview

Q. Please summarize the objectives of Company-owned Weather Stations.

A. The Company's internal Meteorologist conducted a review on weather systems that impact the Company's grid. As noted in the Liberty Report Part II, on page 94, there is a need to not only track weather conditions but to analyze historical trends that may adjust Consumers Energy's asset management strategy. The Meteorologist reviewed existing practices and concluded that there are large gaps of weather data throughout the service area due to the limited number of National Weather Service stations in Michigan. The data gathered from these additional weather stations will be used to:

- Inform storm preparation activities to speed up outage restoration by positioning resources;
- Analyze historical trends looking for a connection between various weather systems and the resiliency of the assets; and
- Feed data into the Company's outage prediction modeling to provide improved accuracy.

Q. What type of data will be captured by these Weather Stations?

A. Key data to be collected includes temperature, wind speed, wind direction, barometric pressure, humidity, solar radiation, rainfall, fuel temperature, fuel moisture, and soil moisture. This data will be available for advanced analytics across many areas in the Company.

Q. How many weather stations are being proposed across the service territory?

A. The Company plans to install up to 100 weather stations by 2027. The Company anticipates efficiencies will be gained from working with a professional installation vendor and is targeting to have all weather stations installed with the bridge period.

Q. How many weather stations have been installed since this program began?

A. As of March 1, 2026, five weather stations have been installed; with two located in high wildfire risk areas.

Q. Describe the analysis used to determine the total number of needed weather stations.

A. A 2018 report by EPRI[8], titled *Determining the Optimal Locations for Weather Sensors in a Mesonet*, stated the optimal-level grid network for the Company's type of topography is roughly 15 km (9.32 miles) in between sites. The Company has proposed installing weather stations 16 km (10 miles) in between sites, which is a slightly greater distance than the ideal grid network. That is equivalent to one weather station per 100 square miles. To complete the 10-mile by 10-mile grid resolution within the Company's more than 28,000 square mile service territory, Consumers Energy would need to install 100 Company-owned weather stations. This grid resolution includes the already installed National Weather Service weather stations. While the National Weather Service provides access to weather stations, large gaps remain around the state. The largest gaps in weather station data occur in Northeast Michigan. The average county land size in Northeast Michigan is 560 square miles, where the average county only has one to two weather stations monitoring wind. Worse yet, there are currently zero public weather stations within the entirety of Gladwin County that monitor wind speed and wind direction.

[8] *Determining the Optimal Locations for Weather Sensors in a Mesonet*. EPRI, Palo Alto, CA: 2018. 3002007610. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwjQt82vyZSNAxWA4MkDHT-SOcgQFnoECCUQAQ&url=https%3A%2F%2Frestservice.epri.com%2Fpublicdownload%2F000000003002007610%2F0%2FProduct&usg=AOvVaw283Pq0-tgIqWG5IgGeYdyr&opi=89978449

Q. What benefits do you expect these Weather Stations to provide?

A. To prepare for severe weather, the Company employs the prestaging of line workers close to where the greatest impact is expected. These weather stations will provide real-time weather data signaling the most optimal placement of resources as a system is progressing across the state. Acting on this improved situational awareness enables faster restoration times for customers. Reducing the duration of a storm not only helps the Company meet the MPSC Service Quality and Reliability Standards, but it can also avoid service restoration costs. As shown in Exhibit A-165 (SAM-8), which also contains a revenue recovery calculation, the Company estimates avoided CMI of 12,575,250 from 2027 through 2036. Beyond the operational benefits, additional analytics will be performed to determine asset resilience and performance. The observed weather conditions will provide the Company insight to improve equipment, material, and engineering standards.

Over time, increased weather data can be used in the Company's outage prediction. A study was published through EPRI, titled *Case Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application,*[9] concluding that an increase in spatial and temporal resolution increased the accuracy of forecast models.

Q. What benchmarking was performed to support this investment?

A. Weather stations can provide valuable information around complex forecasting topography. Central Hudson Gas and Electric took part in the 2018 EPRI study, determining the optimal number of weather stations to maintain in their grid. Utilities across the United States have been able to increase their situational awareness for wildfire risk mitigation by installing weather stations across their electric grid. Portland General

[9] *Case Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application.* EPRI, Palo Alto, CA: 2016. 3002004268.

Electric ("PGE"), for example, has a network of more than 80 weather stations that provide detailed weather data, as well as AI-enhanced cameras that assist with fire detection and awareness. In addition, San Diego Gas and Electric ("SDG&E") currently has more than 220 weather stations within a 4,000 square mile service territory. While wildfire detection is a growing space for many weather station vendors, the Company remains focused on improved outage response when storms impact customers.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period in this investment category as identified in Figure 7 below.

Figure 7
WEATHER STATIONS EXPENDITURE SUMMARY ($000)

	Bridge Period (Jan '26 - Apr '27)	**Test Year (May '27 - Apr '28)**
Weather Stations	1,870	0

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

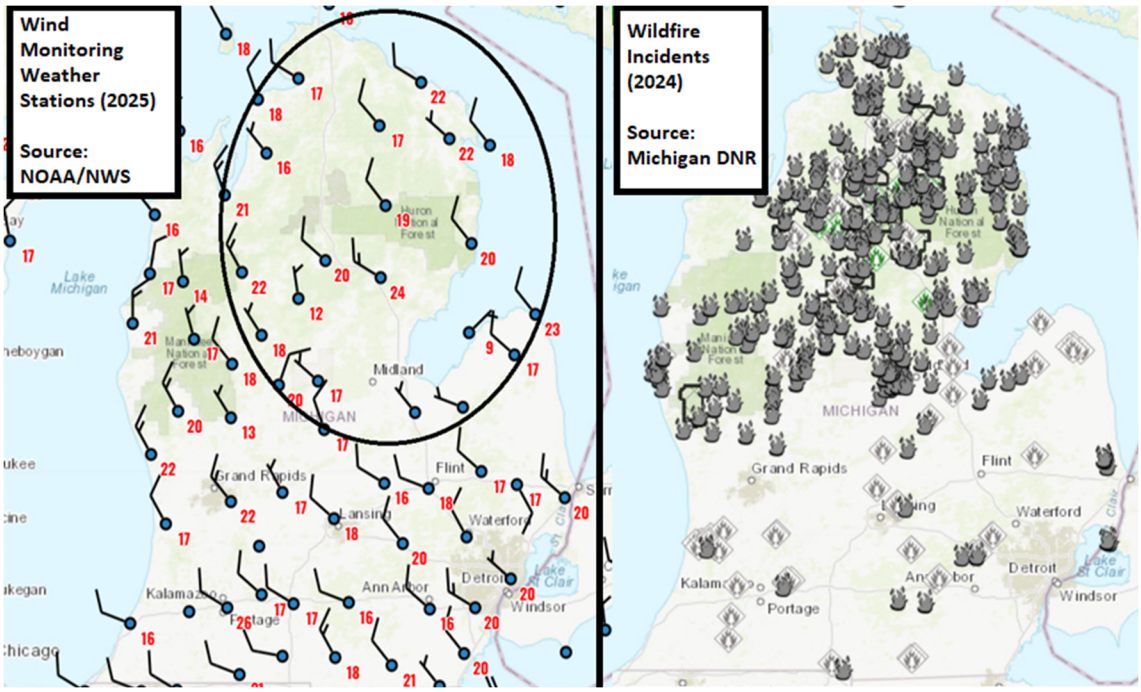
A. The decision to add weather stations to the electric grid was primarily made as a result of the Reliability Roadmap's identification of the risk of increasingly severe weather resulting from climate change. As seen in the Reliability Roadmap, the Company has experienced repeated instances of strong winds causing large-scale outages and a general increase in Major Event Days per year. The number of days with thunderstorms in the state of Michigan is anticipated to increase through 2050, as described in the Reliability Roadmap, see Exhibit A-95 (EMD-11) Figure 18. The greatest potential for an increase in

thunderstorm days is in Northeast Michigan, where the least amount of weather data is available and where the fewest weather stations currently exist. Thunderstorms pose wind and lightning concerns, which correlate to potential outages and wildfire initiation risk.

Northeast Michigan additionally holds the highest wildfire risk zone within the Company's service territory. Figure 8 below compares the current National Weather Service wind monitoring weather stations with the wildfire incidents that occurred in 2024. Currently, the region with the highest wildfire risk in Michigan is correlated with the least amount of weather station data.

FIGURE 8

COMPARISON OF WIND MONITORING WEATHER STATIONS TO WILDFIRE INCIDENTS



There are currently 26 wind-monitoring National Weather Service weather stations in the Company's Northeast electric service territory, covering nearly 6,800 square miles. Based on the ideal 10-mile by 10-mile grid spacing between weather stations, Northeast Michigan

should have at least 68 weather stations covering that region. The Company plans to install 44 of the proposed 100 weather stations in Northeast Michigan to increase situational awareness.

The Liberty Report Part II, pages 112-113, conclusion 6, determined more needs to be done to improve outage modeling. This additional weather data can be incorporated into the Company's modeling and used to make operational decisions that limit the impact of outages to customers.

Q. Please provide an example event when additional weather stations could have been beneficial to the Company and customers.

A. Please see a description of the severe weather conditions experienced in 2025 in Company witness Jeffrey P. Dickey's testimony starting on page 3.

VIII. Summary

Q. Please provide a summary of your testimony and the intent of investing in Grid Automation to support the Company's electric distribution system.

A. My testimony provided an overview of the Company's efforts to establish an automated and modernized electric grid. Grid Automation projects were shown to have provided benefits to customers through better reliability and cost control. The Company has a track record of proven successes as seen through the delivery of the ADMS, ATR Loop Schemes, Line Sensors, CVR, and other programs that have become a normal part of running the electric grid. Grid Automation investments have been shown to support the key objectives of the Reliability Roadmap and play a key role in building the grid of the future, as the Company installs new technology with proven capabilities on the electric distribution system.

Q. Please summarize the Grid Automation capital expenditure plan in this filing.

A. The Grid Automation capital expenditure plan outlined in this testimony is summarized in Figure 9 below, and as shown in Exhibit A-87 (EMD-3).

Figure 9
GRID AUTOMATION EXPENDITURE SUMMARY ($000)

	Bridge Period (Jan '26 - Apr '27)	**Test Year (May '27 - Apr '28)**
Grid Automation	15,184	8,260

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Jennifer M. Partlan, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently Director of Low Voltage Distribution ("LVD") System Planning.

Q. What are your responsibilities as Director of LVD System Planning?

A. My responsibilities as Director of LVD System Planning include oversight of activities associated with planning for the Company's low voltage electric overhead and underground assets, as well as the Company's streetlight assets.

Q. What is your formal educational experience?

A. I earned a Bachelor of Science degree in Electrical Engineering from Oakland University in 2000. I earned a Master of Science degree in Engineering Management from the University of Michigan – Dearborn in 2005.

Q. Please describe your work experience.

A. I began my career with Jacobs Engineering in 2000 as an Instrumentation and Controls Engineer, designing, programming, and commissioning equipment for test cell facilities for automotive companies. In 2008 I started work at General Dynamics in the software lab developing and testing software for military vehicles. In 2010, I worked at General Motors in the transmission testing lab as a test engineer until I started at Consumers Energy in 2011 in the Tools and Work Methods team as the Electrical Team Lead. My duties included working with the team that conducted tool demonstrations, updated work methods

processes, and conducted site visits. From 2013 to 2018 I worked in the Substation Construction department as an Electric Construction Supervisor, working as the project manager for contractors conducting upgrades or modifications to existing substations or building new Consumers Energy substations. I started in the LVD Planning department in 2018 as the Engineering Manager over the Grand Rapids Zone. My team monitored and proposed projects for the LVD lines in relation to capacity, reliability, and managing customer concerns and repetitive outages. In March 2025, I assumed my present position as Director of LVD System Planning.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the following MPSC case:

Case No. U-21870 Electric General Rate Case

Q. What is the purpose of your direct testimony in this proceeding?

A. As introduced by Company witness Emily M. Duke, the purpose of my direct testimony is to explain the Company's projected capital costs in the electric LVD lines system. I will explain the purpose of this spending and the corresponding benefits. The testimony will describe the LVD work and associated costs for the New Business, Demand Failures, Asset Relocations, Reliability, and Capacity programs with a subsection for each LVD lines subprogram. This will include the capital costs for LVD Metering and LVD Transformers, and the Tools sub-program in the Electric Other program.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is 2025. The bridge period consists of 16 months ending April 30, 2027. The test year is the 12 months ending April 30, 2028.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-167 (JMP-1)	Bridge Period LVD Project List;
Exhibit A-168 (JMP-2)	Test Year LVD Project List;
Exhibit A-169 (JMP-3)	Conservation Voltage Reduction Measurement and Verification Independent Assessment;
Exhibit A-170 (JMP-4)	LVD Repetitive Outages Investment Reliability Data;
Exhibit A-171 (JMP-5)	Ferrand Estates Concept Approval; and
Exhibit A-172 (JMP-6)	Summary of Overhead to Underground Project Benefit Cost Analyses (BCA).

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes, except that Exhibit A-169 (JMP-3) is an independent assessment prepared by a third party.

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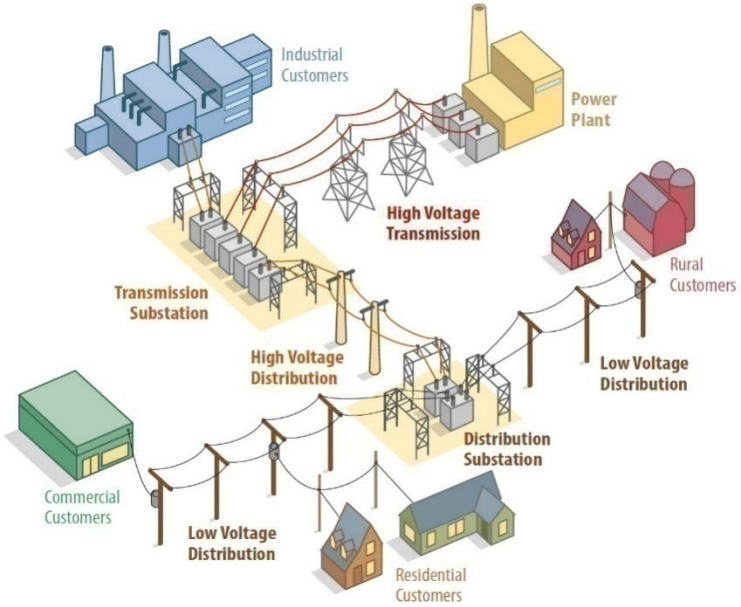
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LVD SYSTEM OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. As discussed by Company witness Duke, the Company's electric distribution system is comprised of the high voltage distribution ("HVD"), LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1. My testimony is concerned primarily with LVD lines.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of over 114,000 total miles of lines, made up of approximately 53,700 miles of primary overhead, 10,600 miles of primary underground, 31,300 miles of secondary overhead, and 18,600 miles of secondary underground. The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number and range of primary voltages differ because the Company acquired several distribution systems from smaller distribution companies over its history. LVD primary voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 Volts and 480 Volts. More than 2,100 LVD circuits serve the Company's approximately 1.9 million electric customers, where a circuit is defined as a combination of electrical devices and hardware that are connected and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.

Q. What challenges are faced by the LVD system?

A. Broadly speaking, the LVD system is expansive and subject to the greatest threat from common outage causes like vegetation, severe weather, equipment failure, unexpected load increases, and third-party damage. The LVD system is largely a radial system that is not capable of continuing service to customers during outages. The LVD system remains configured such that every outage will interrupt service to a number of customers, though the Company's recent efforts in automation and additional fusing have reduced the number of customers impacted by individual outages.

Q. Does the Company have a strategy for addressing these challenges to the LVD system?

A. Yes. The Company provided a detailed strategy in the 2023 *Electric Distribution Infrastructure Investment Plan* ("2023 EDIIP"), also referred to as the "2023 Reliability Roadmap," that was filed in Case No. U-20147 on September 27, 2023. An amended version of the 2023 EDIIP was included in Case No. U-21870 as an exhibit. In the instant case, the Company is again providing this amended version as Exhibit A-95 (EMD-11), and this is referred to throughout my testimony as either the "2025 Reliability Roadmap" or simply the "Reliability Roadmap." Company witness Duke provides direct testimony further explaining the Company's overall distribution strategy. In my direct testimony, I will explain how the Company is investing in the LVD system to provide needed reliability and resiliency of electric service to customers, and how these investments relate to the plan outlined in the Reliability Roadmap.

LVD PROGRAMS WITH CAPITAL SPENDING

Q. How does the Company classify its LVD capital investments?

A. As discussed by Company witness Duke, the Company makes capital investments under two broad classifications, *unplanned* and *planned*.

- Unplanned investments include the New Business, Demand Failures, and Asset Relocations programs, and the LVD New Business Capacity subprogram; and
- Planned investments include the Reliability program and the remainder of the Capacity program.

Q. Please summarize the LVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend $1,302,901,000 in capital projects on the LVD system in the bridge period, and $1,017,412,000 in the test year. Note that the projected investment level for the bridge period is reflective of a 16-month period; on an

annualized basis, this would translate to $977,175,750 in annual investment. This investment plan is summarized by the capital programs shown in Figure 2 below.

FIGURE 2
LVD CAPITAL EXPENDITURES BY PROGRAM ($000)

Program	2025 Actuals	Bridge Period	Test Year
New Business	$267,020	$343,234	$260,278
Demand Failures	$293,531	$251,710	$151,356
Asset Relocations	$88,913	$168,109	$131,401
Reliability	$181,542	$446,311	$379,846
Capacity	$57,713	$83,885	$86,253
Electric Other	$5,796	$9,652	$8,277
Total	$894,515	$1,302,901	$1,017,412

Q. How has the level of investment in the LVD system been impacted by the Reliability Roadmap?

A. The Reliability Roadmap has led the Company to project increased investment levels in key LVD subprograms in the Reliability and Capacity programs, compared to pre-Reliability Roadmap historical levels. I will address the increase in those LVD subprograms throughout my direct testimony in their respective sections, but I will note here that the largest impacts from the Reliability Roadmap regarding LVD lines are to the LVD Lines Reliability, Resiliency, and LVD Lines Capacity subprograms.

Q. What specific LVD lines projects does the Company expect to invest in during the bridge period and test year?

A. Specific projects are identified in Exhibits A-167 (JMP-1) and A-168 (JMP-2). The exhibits include projects identified with scope, cost, location, benefit type, and benefits. The two quantitative benefit types are:

- Customer outage minutes avoided (also referred to as minute interruptions and abbreviated "CMI"): Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.

- Customers impacted: Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as "1."

In addition to the quantitative benefits associated with projects, some projects may be completed to enhance safety for employees or the public, for regulatory compliance, based on the Company's obligation to serve customers, or other reasons. Company witness Duke provides more details about how the quantitative benefits are calculated. Throughout my direct testimony, I will explain more about the specific benefits of each investment sub-program.

New Business Program

Q. What portion of the New Business Program will your testimony discuss?

A. The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. Company witness Duke introduces and further discusses this program. My testimony will focus on the LVD subprograms:

(i) LVD Lines New Business; and

(ii) LVD Transformers.

Projected spending and benefits are explained in detail in the subprogram section below. LVD Transformers are discussed in a separate section later in my direct testimony.

LVD Lines New Business

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Lines New Business subprogram.

A. The LVD Lines New Business subprogram includes the capital cost of serving new commercial, industrial, and residential customers. These costs include the necessary overhead and/or underground distribution extensions and enhancements required to

complete new service connections, including the cost for new plats and developments. The Company may also have to construct line extensions to connect new customers, extending the distribution line itself to reach the new customer's service.

Projects within this subprogram are initiated by customers whom the Company must serve pursuant to tariff requirements. In general, the Company does not have advanced knowledge of LVD Lines New Business projects in the preceding year, as the projects are generally completed within the same year that they are requested. The projections for installed units and investment are based upon historical activity with adjustments for anticipated variations in business, with input from external data sources, covered in more detail later in my testimony.

Q. What benefits will customers realize through the Company completing work in the LVD Lines New Business subprogram?

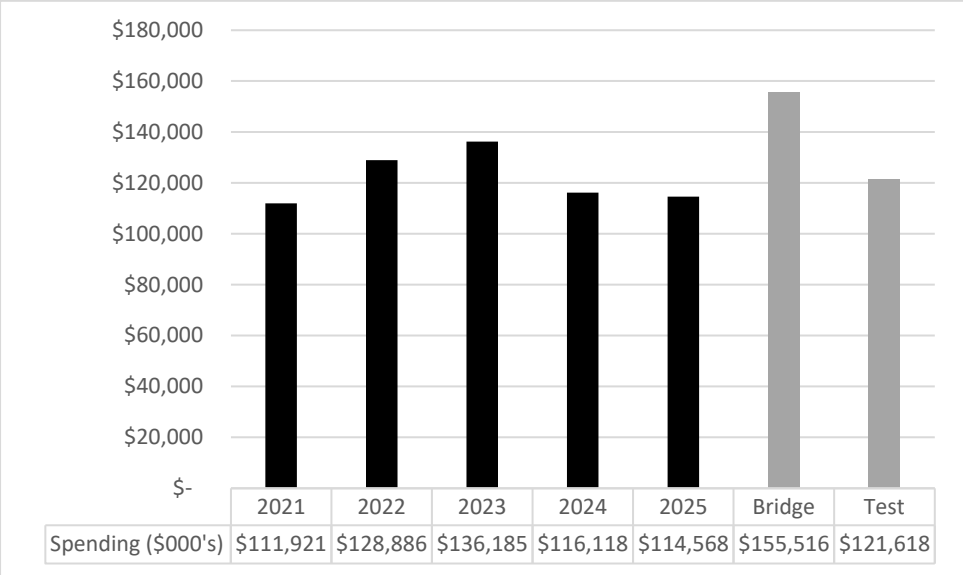
A. Fundamentally, new customers benefit because customers' homes, businesses, and other facilities receive access to the grid and the electricity that it provides. This also supports economic growth in Michigan by enabling new residential, commercial, and industrial facilities to access electricity. The projected spending level will allow the Company to provide a new service installation to every customer who requests it.

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines New Business subprogram?

A. The Company is projecting LVD Lines New Business capital expenditures of $155,516,000 in the bridge period and $121,618,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 1, columns (k) and (l). The Company's historical actual spending in

the LVD Lines New Business subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 1, and below in Figure 3.

FIGURE 3
LVD LINES NEW BUSINESS SUBPROGRAM EXPENDITURES



	2021	2022	2023	2024	2025	Bridge	Test
Spending ($000's)	$111,921	$128,886	$136,185	$116,118	$114,568	$155,516	$121,618

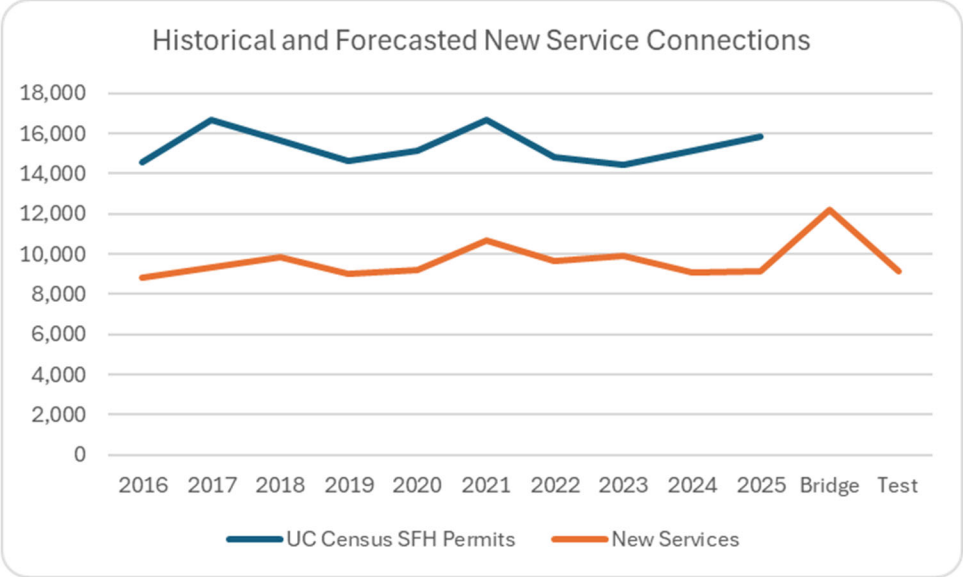
Q. How did the Company develop its projected expenditures in this subprogram?

A. For purposes of this filing, the Company developed the projected expenditures by applying an inflation factor to 2025 actual expenditures. The Company used an inflation rate of 2.9% for 2026, 2.5% for 2027, and 2.2% for 2028. Other than the inflationary adjustment, the Company assumed unit costs remain constant over the period.

Q. What is the Company's forecasted number of new service connections?

A. The Company is projecting to remain flat from 2025 actuals with 9,134 services in the test year and 12,178 services in the bridge period. Figure 4 below shows the Company's historical and projected new service connections.

FIGURE 4
HISTORICAL AND FORECASTED NEW SERVICE CONNECTIONS



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Bridge	Test
UC Census SFH Permits	14,534	16,652	15,633	14,623	15,154	16,670	14,809	14,413	15,137	15,821		
New Services	8,818	9,353	9,864	9,023	9,182	10,651	9,658	9,898	9,058	9,134	12,178	9,134

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

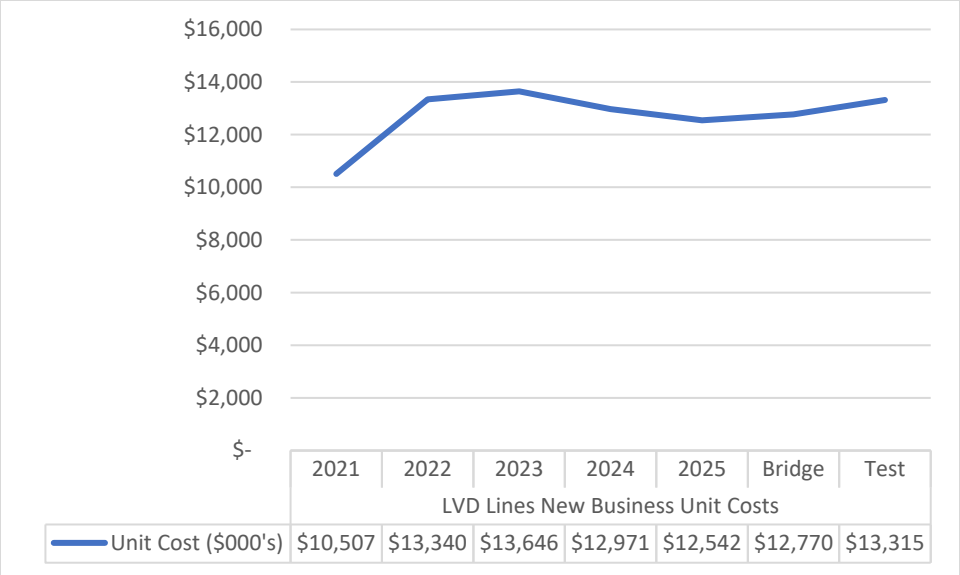
A. Yes, for the overall subprogram. The unit for this subprogram is projects, and the projects undertaken are specifically tailored to the needs of the customer requesting the work. There is a variance of costs among the different projects; however, because of the volume of service connection units, an average unit cost can be used to develop the spend projections for the overall subprogram.

Q. How does the Company project the average cost of new service connections?

A. The Company used its actual historical costs to inform future unit cost projections for new service connections. The Company is projecting unit costs for the bridge period and test year to remain flat relative to 2025 actuals, with an increase for inflation. In 2025, the Company experienced a slight reduction in unit costs. Unit costs in 2025 were $12,542,

down from an average unit cost of $12,971 in 2024, for new electric services. Unit costs have been largely consistent since 2024, after coming down from an increase in 2022 and 2023. Figure 5 below illustrates the historical and projected unit cost for new service connections.

FIGURE 5
HISTORICAL AND FORECASTED UNIT COSTS FOR NEW SERVICE CONNECTIONS



Q. How does the Company address necessary line extensions to connect new residential customers?

A. Residential line extensions may be needed when a customer builds a residential structure far enough away from existing grid infrastructure. The Company may charge customers a contribution in aid of construction ("CIAC") fee for these extensions, depending on length and whether the extension is overhead or underground, per the terms of the Company's tariff. The relevant Company tariff fee was most recently updated in 1989, meaning the charges are out of date, and in the instant case the Company is proposing to update the fee structure. Relevant tariff changes are presented by Company witness Brittani A. Gray.

Q. What is the Company's currently effective CIAC fee structure for residential line extensions?

A. At present, customers are not charged any CIAC fee for residential overhead line extensions less than or equal to 600 feet in length, which was the average extension length at the time the tariff was set. For residential overhead line extensions greater than 600 feet in length, customers are charged $3.50 per foot for the length exceeding 600 feet (a 25% instant refund makes this effectively $2.62 per foot). Customers are charged $4.80 per foot for underground extensions under 600 feet in length. For underground extensions greater than 600 feet in length, customers are charged $4.80 per foot and an additional $3.50 per foot for the portions of underground extensions greater than 600 feet (although a 25% instant rebate also effectively lowers this from $3.50 per foot to $2.62 per foot). These current effective fees are summarized in Figure 6 below. Note that these fees do not include any padmounted transformer costs, which the customer bears.

FIGURE 6
CURRENTLY EFFECTIVE CIAC FEE STRUCTURE

Description of Line Extension	CIAC Fees
Overhead ≤ 600 feet	$0.00
Overhead > 600 feet and ≤ 2,640 feet	$2.62 per foot ($3.50 – 25%) over 600 feet
Underground ≤ 600 feet	$4.80 per foot
Underground > 600 feet and ≤ 2,640 feet	$4.80 per foot > 600 feet + $2.62 per foot over 600 feet

Q. How does the Company propose to change this CIAC fee structure?

A. The Company proposes keeping residential overhead line extensions less than or equal to 600 feet at no charge to the customer. For residential overhead line extensions greater than 600 feet, the Company proposes to increase the fee to $9.15 per foot, representing inflation

since the fee was last set in 1989. This will continue to carry a 25% instant rebate, making the effective fee $6.86 per foot.

For residential underground line extensions, MPSC Rule 460.511 states that, "In the case of all underground extensions of electric distribution facilities as covered by these rules, the real estate developer or customer shall make a CIAC to the utility in an amount equal to the estimated difference in cost between overhead and underground facilities." The Company has determined that the total lifecycle costs of overhead and underground residential line extensions are effectively equivalent, so the Company proposes to also make underground line extensions at no charge to the customer when less than or equal to 600 feet in length. Likewise, the Company proposes making residential underground line extensions greater than 600 feet $9.15 per foot (minus the 25% instant rebate) for the length exceeding 600 feet, in line with the proposed fee for residential overhead line extensions. These fees will continue to be exclusive of padmounted transformer costs. The new proposed fee structure is shown in Figure 7 below.

FIGURE 7
PROPOSED CIAC FEE STRUCTURE

Description of Line Extension	Proposed CIAC Fees
Overhead ≤ 600 feet	$0.00
Overhead > 600 feet and ≤ 2,640 feet	$6.86 per foot ($9.15 – 25%)
Underground ≤ 600 feet	$0.00
Underground > 600 feet and ≤ 2,640 feet	$6.86 per foot ($9.15 – 25%)

Q. How will these updated fees affect costs for residential customers?

A. Figure 8 below shows comparisons for the CIAC fees that are charged to residential customers under the current fee structure and what they would be charged under the proposed fee structure for various lengths. Note that these illustrative costs include a 25%

instant rebate, but they do not include any costs for new padmounted transformers if they are needed.

FIGURE 8
RESIDENTIAL LINE EXTENSION CIAC FEE COMPARISON

Length	Current Cost Examples	Proposed Cost Examples
Overhead		
300’	$0.00	$0.00
600’	$0.00	$0.00
900’	$788.00	$2,059.00
1,500’	$2,363.00	$6,176.00
2,300’	$4,463.00	$11,666.00
Underground		
300’	$1,440.00	$0.00
600’	$2,880.00	$0.00
900’	$5,108.00	$2,059.00
1,500’	$9,563.00	$6,176.00
2,300’	$15,503.00	$11,666.00

Q. What other impacts will this proposed change for residential line extensions have for customers?

A. In general, this change should make it more economically appealing for residential customers to select underground line extensions. Customers generally find that underground lines are more aesthetically pleasing than overhead lines, they have less impact on customers’ trees, and they improve reliability and resiliency for customers.

Q. Is the Company proposing any electric service connection fees related to this sub-program in the instant case?

A. The Company is proposing to update its residential and general service fees. The new fees are presented by Company witness Brittani A. Gray. As Company witness Gray states, the Company is proposing tariff sheets that include dollar-per-foot charges of $10.20 per foot for residential customer service connections and $17.20 per foot for general service customer service connections, with the same fees for overhead and underground services.

In Case No. U-21870, the Company proposed flat service connection fees. While the Commission approved the Company's proposal, the Commission indicated in its Order that the Company should create a fee structure that considers fixed costs and also reflects variable costs in the instant case. Thus, the Company is proposing the per-foot charges to replace the current flat fees.

Q. How did the Company determine the proposed charges in the instant case?

A. These proposed charges reflect inflation since the last time per-foot costs were calculated and established by the Company ($4.50 per foot for residential customers in 1993; $6.50 per foot for general service customers in 1989). These charges are meant to help recover the Company's costs for installing new services. Note that these charges apply when the customer agrees to the route specified by the Company. If a customer requests a different route, then they are also charged the full incremental cost of the requested route above and beyond what the Company's specified route would have cost.

Q. Does the Company expect the proposed changes in fees to affect the number of overhead and underground services installed?

A. Yes. Currently, 87% of new service installations are underground. Given the change in service fees, the Company expects the percentage of underground services to increase to 99%. The 1% of overhead services is expected to remain for customers where an underground service is not possible due to ground conditions such as wetlands, contaminated soil, etc.

Q. How will customers benefit from underground services?

A. Considering the exposure to weather and trees, storms that pass through the Company's service territory typically affect overhead services much more than underground services.

For example, over the last two and a half years, overhead residential services are approximately 45 times more likely to experience an outage than underground residential services. During storm restoration, the Company prioritizes restoration work that restores large numbers of customers or critical facilities, such as hospitals. Given the focus on reducing the time customers spend without power to meet the Commission's Service Quality and Reliability Standards, the restoration of residential services, which typically impacts only one customer, are often not completed until near the end of storm restoration work. With an underground service, customers are less likely to be subjected to a service-driven outage and the long duration of restoration associated with such an outage.

Q. How does the change in the customer service connection fees impact projected spending in this sub-program?

A. The increased fees are expected to save $2 million in the capital requested for service connections. This savings has already been accounted for in the Company's projections, so there is no further new change to the projected spending.

Q. Are there unit cost differences between new services installed by contractors and those installed by Company employees?

A. Yes. In its final Order in Case No. U-21585, the Commission directed the Company to develop a comparison and present the details in Case No. U-21870, which was done. In its March 27, 2026 Order in Case No. U-21870 ("U-21870 Order"), the Commission directed the Company to analyze the gap between contractor and Company costs and what changes the Company has pursued based on these differences. The results of this analysis are shown in Figure 9 below.

FIGURE 9
COMPARISON OF COMPANY VS. CONTRACTOR UNIT COSTS FOR LVD LINES NEW BUSINESS, 2020-2025

	2020	2021	2022	2023	2024	2025
Company Units	5,383	5,976	6,601	8,923	8,061	8,560
Contractor Units	3,799	4,675	3,057	975	997	537
Company Unit Cost	$9,314	$9,298	$11,334	$12,002	$11,987	$10,882
Contractor Unit Cost	$9,449	$11,134	$16,585	$26,383	$21,013	$39,879

Q. What is shown by this comparison?

A. The numbers in this comparison show that, beginning in 2021, contractor unit costs have increased, whereas Company unit costs have remained relatively level. Correspondingly, the Company shifted much of the work in this sub-program to internal resources. However, it is important to note that in the data sources used to make the calculations in the above table, contractor costs include various additional services performed by the contractors, such as traffic control and hydro excavation. These services are not all necessarily used for work assigned to contractor crews, and the contractor services may in some cases be in support of work performed by Company crews. However, the Company cannot easily separate out contractor costs that exclusively support LVD Lines New Business work, and this makes these year-over-year comparisons difficult. Additionally, some of the contractor costs are fixed, which inflates the calculated unit cost as the number of units completed by contractors decreases.

Even if contractor costs are increasing, the Company cannot completely phase out contractor work for LVD Lines New Business. It is important for the Company to maintain some level of contracted work in this sub-program because contractors provide a level of flexibility and scalability to allow the Company to respond to the unplanned nature of this

work. Contractors also ensure that Company employees are able to work on other jobs, such as in the Reliability program.

Demand Failures Program

Q. What portion of the Demand Failures Program will your testimony discuss?

A. The purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system. Company witness Duke introduces and further discusses this program. My testimony will focus on the LVD subprograms:

(i) LVD Lines Demand Failures; and

(ii) LVD Metering.

Projected spending and benefits are explained in detail in the subprogram section below. LVD Metering is discussed later in a separate section of my testimony.

LVD Lines Demand Failures

Q. Please explain what projects, activities, and other types of work the LVD Lines Demand Failures subprogram expenditures will enable.

A. The LVD Lines Demand Failures subprogram includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated failure. The expenditures will enable the Company to respond to day-to-day equipment failures and perform storm restoration work that is capital in nature. Projects are not planned far in advance in this subprogram, because it is meant to quickly respond to equipment failures and customer interruptions that occur in real-time. The LVD Lines Demand Failures subprogram consists of two investment categories:

Service Restoration Orders and LVD Asset Assessment orders, the latter of which was formerly referred to Security Assessment Inspections.

Q. What work is done in the Service Restoration Orders investment category?

A. Service Restoration Orders consist of work completed on an emergent basis to quickly restore customers who are without power for various reasons, such as following storms or equipment failures.

Q. What work is done in the LVD asset assessment orders investment category?

A. LVD asset assessment orders consist of projects created to fix issues identified in the Company's visual line inspections as discussed further below in my direct testimony on this sub-program.

Q. How does the Company identify and prioritize LVD Lines Demand Failures projects?

A. Once a failure or other damage to the system has been identified, either due to a customer interruption or due to an LVD asset assessment, the Company prioritizes its response by categorizing damage by severity, as either a Priority 1 ("P1") or Priority 2 ("P2"), as shown in Figure 10 below.

FIGURE 10
LVD ASSET ASSESSMENT HAZARD CODES

Code	Description
P1 - Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 - Failures	
P2A	Floating Phase / Neutral
P2B	Broken / Cracked Cross-arm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators
P2E	Pole: Needing Immediate Replacement
P2F	Pin Pulling from or through Crossarm/Pole
P2G	Other Failed Structure or Equipment

Q. How does the Company respond to P1 and P2 failures?

A. P1 failures include problems that require immediate action to repair the damage. This includes threats to public safety, such as downed wires or exposed underground equipment. P1 failures are addressed within 24 hours.

Like P1 failures, P2 failures consist of equipment that has failed, but P2 failures are less urgent. For example, the Company may find an insulator that has detached from its pin; the line would remain energized but no longer in its safe operating condition.

In certain circumstances, the Company may promptly mitigate a P1 failure by reducing it to a P2 condition. For example, exposed cables within a fiberglass pad may be temporarily patched to eliminate the immediate safety risk. While this action resolves the P1 emergency condition, the equipment remains in a failed state and requires permanent replacement. The Company generally seeks to complete P2 repairs within 60 calendar days. However, this timeframe may be extended when equipment has been temporarily bypassed and replacement materials are on order, when engineering review or design is required to confirm pole loading or electrical loading adequacy, or when resources must be prioritized based on system impact or performance considerations.

Q. What approach does the Company use to identify failures on the overhead LVD system?

A. In early 2022, the Company recognized that deterioration was contributing to failures of overhead structures and equipment, increasing System Average Interruption Duration Index ("SAIDI"). Replacement of those failures on an emergent basis cost more than proactive identification and repair. Accordingly, the Company enhanced its focused assessment program of the LVD overhead system in 2022. The inspections now identify

only P1 or P2 failures (note that these are actual failures, in that equipment is already broken, even if customers have not yet been interrupted). This visual line assessment and maintenance approach is supported by the Electric Power Research Institute ("EPRI"). EPRI's 2015 technical report, *Distribution Grid Resiliency: Overhead Structures*,[1] page 9-13, states: "Utility field tests showed failures far from tree impacts, particularly at weak equipment. Line inspectors can spot some of these weaknesses, particularly cracks in pole tops and cracked or rotten crossarms. Identifying and fixing these can prevent breakage and reduce overall restoration time." EPRI is describing the items that are contained within the Company's P1 and P2 failure categories.

Q. Please summarize the recent assessments.

A. The Company completed an assessment of 100% of its LVD overhead primary system in 2022 and 2023. The P1 and P2 failures identified in these inspections were corrected as part of this subprogram. Based on the findings and benefits of these assessments, the Company began assessing 50% of its overhead LVD system annually starting in 2024.

Q. How many failures were identified through these focused LVD asset assessments?

A. In 2022, the Company identified 6,814 P1 and P2 failures. In 2023, the Company identified 10,738 P1 and P2 failures. In 2024, the Company identified 10,965 P1 and P2 failures. In 2025, the Company identified 6,204 P1 and P2 failures. On average the LVD asset assessments identified one failure for every three miles of line through 2024, and one failure for every four miles of line in 2025.

[1] *Distribution Grid Resiliency: Overhead Structures,* https://www.epri.com/research/products/000000003002006780

Q. Are LVD asset assessments the only investment needed to improve SAIDI?

A. No. While correcting failures identified during LVD asset assessments mitigates customer outages related to deterioration and other defects, this activity alone is insufficient to improve SAIDI overall. Mere correction of failures does not enhance the overall system in a proactive or comprehensive manner; rather, it simply corrects the defect at a single point on the system. Therefore, even when LVD asset assessment work is completed, the Company still must make investments in other sub-programs to improve SAIDI, particularly in the Reliability sub-programs discussed later in my direct testimony, in order to get ahead of system deterioration.

Q. What are some examples of failures found in these focused LVD asset assessments?

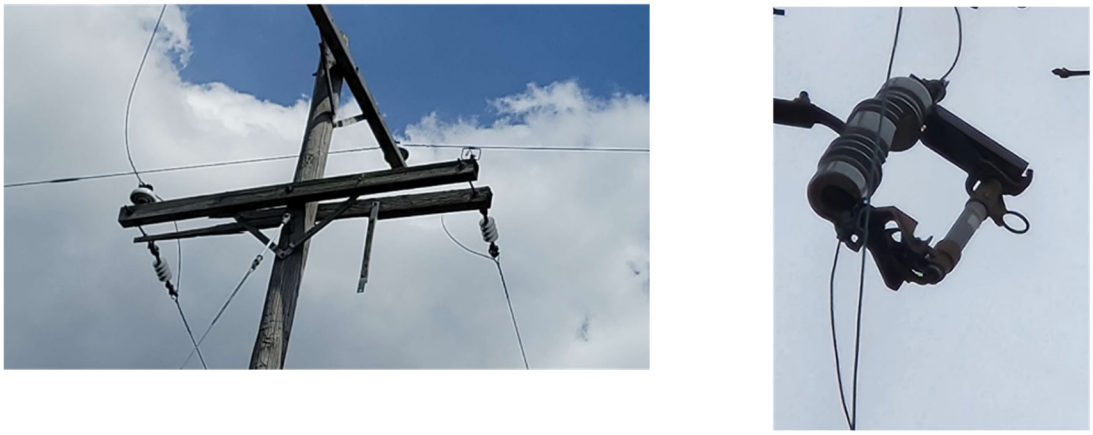
A. The pictures below include examples of P2 failures identified during the assessments in 2025. In the left photo of Figure 11, the lightning arrestor is damaged due to a lightning strike and needs to be replaced. In the right photo of Figure 11, decay and woodpecker damage has greatly undermined the strength of the pole.

FIGURE 11
LVD P2 FAILURES IDENTIFIED THROUGH LVD ASSET ASSESSMENTS



The left photo of Figure 12 depicts a cracked and split crossarm. The photo on the right of Figure 12 is of a cracked cutout where the top half has broken off.

FIGURE 12
LVD P2 FAILURES IDENTIFIED THROUGH LVD ASSET ASSESSMENTS



Q. When the Company determines that service restoration activity is required, what types of projects are considered?

A. The Company performs the following types of service restoration capital work:

- Failed Underground Cable – When a failure occurs on an underground cable, the Company identifies and fixes the fault immediately to restore service to customers. If the underground cable is looped (has feeds from multiple directions), the fault is isolated and service to customers is restored until the permanent restoration is completed within this program;
- Failed Distribution Transformer – These failures are addressed immediately and could warrant further evaluation to determine if the transformer was adequately sized for the load, which, in some cases, leads to replacement of the existing transformer with a larger one;
- Car-Pole Accident – When car-pole accidents result in damage to poles, the Company immediately assigns an available crew to ensure safety of the area, replace the pole (and potentially the pole top), and restring or splice the conductor;
- Broken Cross-arm, Pin/Insulator, or Pole – When poles and other components fail, electric service may be interrupted, or public safety might be affected where the wire is left hanging below the required clearance or out of normal operating position. The Company will replace any broken equipment (i.e., a cracked cross-arm); and

- Failed Overhead Conductor – When overhead wires fail due to age, deterioration, weather, trees, etc., it typically causes a wire down, which can pose a major public safety hazard. The Company addresses these conditions immediately.

Q. What benefits will customers realize through the Company completing work in the LVD Lines Demand Failures subprogram?

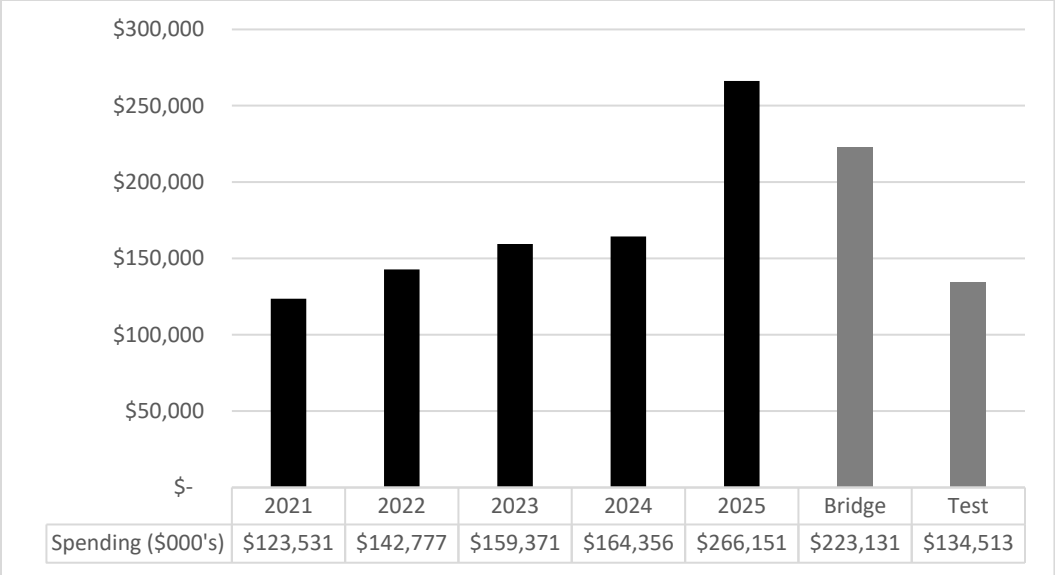
A. This subprogram is essential for the restoration of service to customers for the Company to meet its obligation to serve. Absent investment in this category, customers would remain without electric service because this program funds the basic work necessary to restore electrical service following a failure. Proactive identification of P1 or P2 failures provides a reliability benefit to customers, by improving the condition of system equipment when failed components are replaced, and placing the system back into a normal operating condition, eliminating a likely outage in the future. EPRI also identified this work as a benefit that "…can prevent breakage and reduce overall restoration time." EPRI further noted no drawbacks or risks with this approach. The Company estimates, using its Advanced Distribution Management System ("ADMS") outage data, that the effort in 2022 to identify and remedy P1 and P2 failures reduced system SAIDI, excluding Major Event Days ("MEDs"), by 3.7 minutes through fewer customer outages. In 2023, this effort reduced system SAIDI, excluding MEDs, by 4.0 minutes through fewer customer outages; in 2024 it was reduced by 6.2 minutes; and in 2025 it was reduced by 4.5 SAIDI minutes.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Demand Failures subprogram?

A. The Company is projecting LVD Lines Demand Failures subprogram capital expenditures of $223,131,000 for the bridge period, and $134,513,000 for the test year, as shown in Exhibit A-87 (EMD-3), line 6, columns (k) and (l). The Company's historical actual

spending in the LVD Lines Demand Failures subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 6, and below in Figure 13. Historical spending from 2021 in LVD Lines Demand Failures also included the streetlight failure investment category.

FIGURE 13
LVD LINES DEMAND FAILURES SUBPROGRAM EXPENDITURES



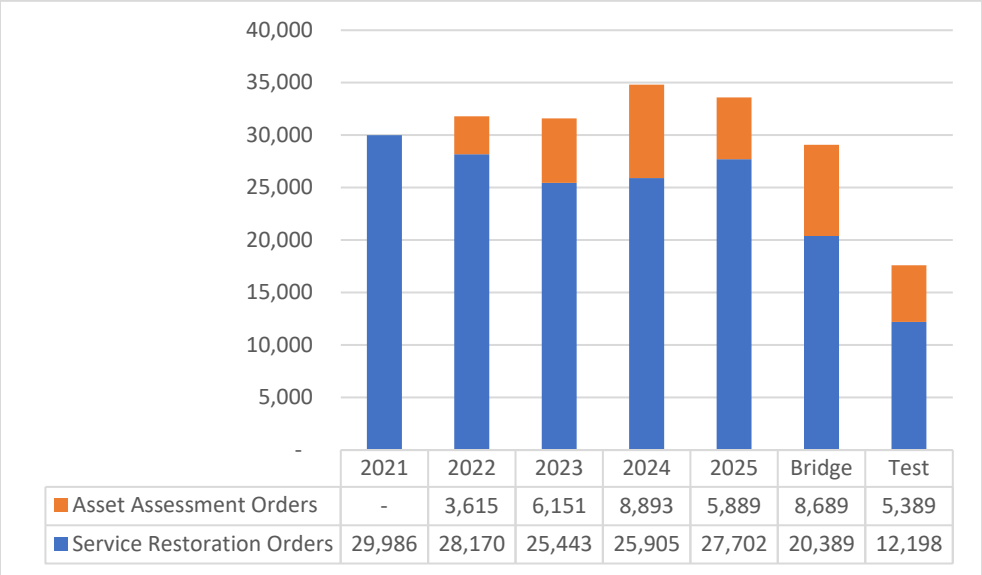
	2021	2022	2023	2024	2025	Bridge	Test
Spending ($000's)	$123,531	$142,777	$159,371	$164,356	$266,151	$223,131	$134,513

Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting it will need to complete 29,078 total orders in the bridge period, consisting of 20,389 Service Restoration orders and 8,689 LVD asset assessment orders. Within the test period, the Company is projecting it will need to complete 17,587 total orders, consisting of 12,198 Service Restoration orders and 5,389 LVD asset assessment orders. The average unit cost for both periods for Service Restoration and LVD asset assessment orders is $8,600 and $5,500, respectively. The Company anticipates that its efforts to proactively identify P1 and P2 failures will mitigate the need for a higher number of orders as efforts better match the rate of system deterioration. The historical and projected number of orders is shown in Figure 14 below. However, the Company's electric

distribution system continues to experience weather challenges, which may require an increased number of service restoration orders to be completed.

FIGURE 14
LVD LINES DEMAND FAILURES UNITS



	2021	2022	2023	2024	2025	Bridge	Test
Asset Assessment Orders	-	3,615	6,151	8,893	5,889	8,689	5,389
Service Restoration Orders	29,986	28,170	25,443	25,905	27,702	20,389	12,198

Q. Please explain the year-over-year variation in spending in this subprogram.

A. Spending increases in this subprogram over the past five years have primarily been driven by unit volume and unit cost. The four-year average number of interruptions from 2021 to 2024 was 52,000 per year. In 2025 there were 65,000 interruptions. In 2025 the unit cost for service restoration orders increased because there were more capital replacements during storms than historical average levels, particularly during a large ice storm in March and April 2025 and a large windstorm in May 2025. This meant that, for the typical service restoration order, more capital costs were incurred, which translates into a higher capital unit cost in this sub-program.

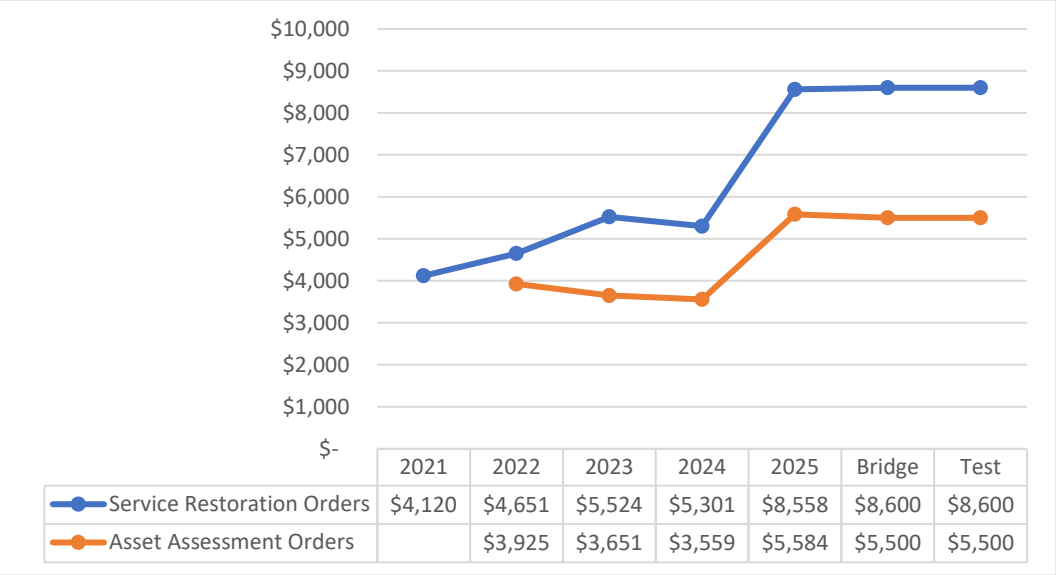
The Company expects that this will continue to exist going forward, with the increased instances of severe weather like tornados and ice storms requiring rebuilding of LVD assets during restoration. The projected bridge period and test year spending is based

on the 2025 actual unit costs; as of the filing of the instant case, 2026 unit costs have been comparable to those from 2025.

Q. What are the historical unit costs for the LVD Lines Demand Failures subprogram?

A. The historical and projected unit costs of service restoration orders are provided in Figure 15 below:

FIGURE 15
LVD LINES DEMAND FAILURES UNIT COSTS



	2021	2022	2023	2024	2025	Bridge	Test
Service Restoration Orders	$4,120	$4,651	$5,524	$5,301	$8,558	$8,600	$8,600
Asset Assessment Orders		$3,925	$3,651	$3,559	$5,584	$5,500	$5,500

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. Yes. Unit costs can provide a generally reasonable expectation of the overall average project cost within the LVD Lines Demand Failures subprogram. However, any individual project in this subprogram can range from a few hundred dollars to replace pins and insulators to as high as $500,000 to replace failed underground cable and equipment.

Asset Relocations Program

Q. What portion of the Asset Relocations Program will your testimony discuss?

A. The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, as well as internal Company projects. Company witness Duke introduces and further discusses this program. My testimony will focus on the LVD Asset Relocations subprogram. Projected spending and benefits are explained in detail in the subprogram section below.

LVD Asset Relocations

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Asset Relocations subprogram.

A. The LVD Asset Relocations subprogram responds to internal and external requests to relocate LVD lines. This subprogram also includes "make-ready" work to prepare LVD poles for third-party attachments; make-ready work can include physical relocation of a pole, but it may also include work to strengthen or replace a pole to allow it to support additional weight. State and municipal agencies, private property owners, and other Consumers Energy departments make requests for relocations; in addition, telecommunications companies request make-ready work so they can attach phone and cable lines and cellular equipment on poles. The subprogram includes any reimbursements from the requesting party, which directly offset expenses incurred to perform the work. The annual subprogram expenditures are based on the cost to relocate less the reimbursements received. Due to the demand-based nature of this subprogram, the Company does not follow a specific planning cycle and generally cannot plan relocation projects far in advance. Each request contains different timelines and requirements based

on the nature of the request, and the Company constantly adjusts timing of projects to meet customer schedules. The Company projects its spending levels based on historical activity, while also accounting for observed trends, particularly related to economic activity.

Q. When does the Company request reimbursement for a third-party initiated relocation request?

A. The Company seeks reimbursement for a third-party initiated relocation request anytime a requesting party requests relocation of Company facilities where the Company has existing, valid rights for the location of its facilities.

Q. Does reimbursement match the cost of relocation?

A. Reimbursement does not always match 100% with the cost of the relocation because the reimbursement request is based on a design estimate. The actual construction costs may come in higher than the design estimate due to unforeseen operational expenditures, such as changes to field conditions, safety mitigation (i.e., traffic control), or other factors. In addition, there may be times when it is in customers' best interest to perform some additional rehabilitation work to adjacent structures or equipment that would not be billed to the requesting party.

Q. How does the Company use information provided by a party requesting relocation?

A. The Company studies the descriptions, maps, surveys, designs, and other documentation provided by the requester, and combines that documentation with internal maps and field measurements to determine what Company facilities, if any, require relocation and where assets should be relocated.

Q. What actions does the Company take when relocation is required?

A. For requests requiring significant relocation or changes to the LVD system, the Company evaluates the proposed changes against a load flow analysis and reliability assessment to determine if relocation will have an adverse effect on the system. If a proposed relocation will negatively impact the reliability or capacity of the LVD system, changes would be necessary. For example, a customer could request relocation of facilities to the edge of their property line, but that move could put the facilities in dense vegetation, making the line less accessible and requiring more line clearing. In that case, the Company would work with the customer to find a better route that meets the customer's needs without impeding reliability. On the other hand, if the relocation significantly changes the length of conductor, it may create a capacity issue and the conductor would need to be upgraded in size.

Q. Please describe the types of projects that the Company includes in the LVD Lines Relocation subprogram.

A. The Company categorizes requests for relocation as:

(i) customer requested (government agencies or private property owners) and requested by other departments within Consumers Energy;

(ii) relocation of LVD underbuild on HVD poles; or

(iii) attachment parties requesting make-ready work.

Q. What is the nature of relocation requests made by government agencies?

A. Government agency requested LVD relocations can fluctuate for many types of projects, such as road and bridge widening or improvements, repairs to municipal facilities, and streetlight and traffic signal modifications. Road and bridge widening, or improvement projects, require the Company to move poles, wires, and other LVD equipment due to

changes to the road location and grade, and to provide proper clearance for any large equipment that the road construction contractors have on site. Large additions to civic buildings can also lead to local governments asking the Company to relocate LVD assets to accommodate those projects. Government agency timelines can vary widely based on size and complexity.

Q. What is the nature of relocation projects requested by private property owners?

A. Private property owner requests vary widely based on the type of project and project timeline. Property owners request LVD relocations for building additions, logistics, landscaping, or other construction projects. Private landowners often request relocation of overhead lines out to the road or underground, particularly to facilitate moving large farm equipment. Residential customers often request relocation of LVD lines to facilitate building an addition, pool, shed, barn or landscaping feature, such as a pond or berm. Commercial customers often request relocation of poles from a parking lot or other area.

Q. What is the nature of relocation requests generated within the Company?

A. Relocation requests within the Company primarily arise when planned work in other groups—such as HVD Planning, Substation Planning, or Metro Planning—requires existing LVD equipment to be moved. Most of these requests involve relocating LVD "underbuild," which refers to LVD equipment mounted on HVD poles below the high-voltage lines. This work can also include building a new LVD tie line to support a load transfer, keeping customers energized while a substation or HVD line is de-energized to support work on those assets.

For LVD underbuild on an HVD pole that is being replaced as part of planned or emergent HVD work, the attached LVD equipment must also be rebuilt and transferred to

the new pole to maintain proper configuration and avoid leaving LVD equipment in a non-standard or abandoned state. This program ensures that LVD assets are appropriately updated whenever HVD projects affect shared structures.

The projects listed in Exhibit A-167 (JMP-1), page 1, and Exhibit A-168 (JMP-2), page 1, respectively show the HVD planned line rebuild projects and the HVD miles which will include pole replacements and therefore require LVD assets to be transferred to the new poles. The LVD miles portion is proportional to the HVD miles.

Q. What is the nature of relocation requests for make-ready work?

A. Make-ready work is initiated through the Company's pole attachment permitting process after an applicant, typically a communications company, requests to place new attachments or modify existing attachments on Company poles. The scope of make-ready work for each application is determined by field measurements and engineering analysis of existing conditions with the applicant's proposed attachment characteristics, which is evaluated to meet National Electric Safety Code ("NESC") requirements. Make-ready work can include a range of construction activities, including but not limited to raising electric conductors and equipment, adding or manipulating down guys, effectively grounding streetlight brackets, raising or lowering existing communications attachments, and pole replacements. In recent years, make-ready work has taken on increased importance due to the rollout of government infrastructure programs designed to expand access to broadband internet, particularly in rural areas.

Q. What benefits will customers realize through the Company completing work in the LVD Asset Relocations subprogram?

A. This subprogram primarily functions to serve customer requests, whether they are internal or external. However, every time old or obsolete equipment is replaced through this subprogram, reliability improves because of the new equipment installed to the latest standards implemented at the time. Relocations performed to support HVD or substation work allow maintenance work on those HVD or substation facilities before a failure causes an outage and ensuring customers remain energized during the work. Some HVD or substation projects may require equipment to be de-energized to perform the work safely. By constructing new LVD tie points allowing for load transfer opportunities, customers remain energized and the work can be performed safely. Preparing the LVD system for this work can save many customer-outage-minutes, as an outage would typically de-energize more than one circuit on these systems, with an average of 1,000 customers per circuit, for three hours or more. When LVD projects can support a planned load transfer for HVD and substation work, the Company can perform the work in a controlled environment with little or no outage to customers. Additionally, as mentioned above, some relocation requests provide clearance for large equipment like farm machinery and road construction equipment. Without sufficient clearance, that machinery may contact the LVD system, causing an outage, putting the operator or other members of the public in danger, and causing thousands of dollars of damage.

Q. How does the Company identify LVD Asset Relocations projects?

A. The activity in this subprogram is entirely driven by requests from both external and internal stakeholders. For all project requests, a party submits a request that includes

timelines for completion if applicable, the project purpose, contact information, and any other pertinent information. For many municipal projects and large internal projects, the Company holds site meetings to gather further information.

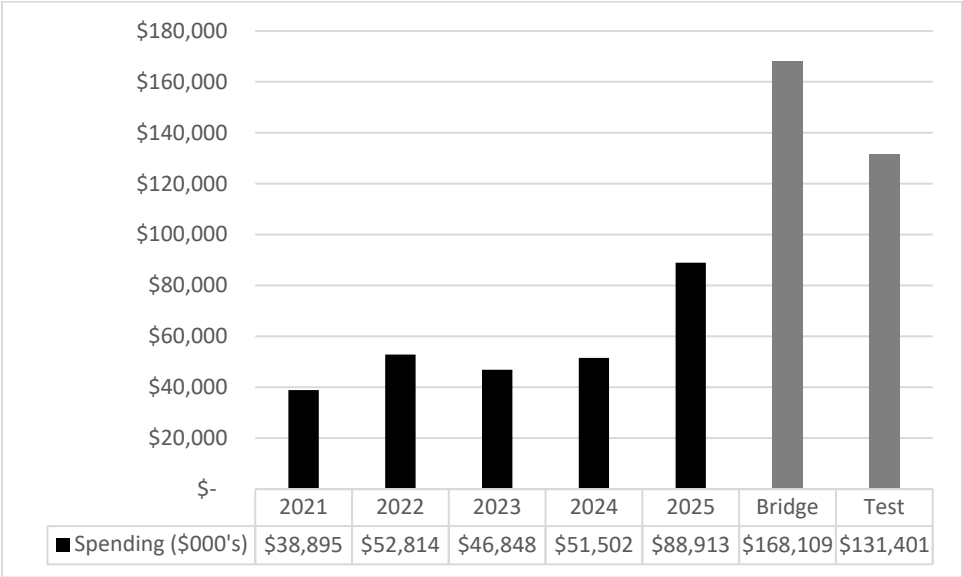
Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Asset Relocations subprogram.

A. The Company has identified known projects for the bridge period and test year, which are listed in Exhibit A-167 (JMP-1), page 1, and Exhibit A-168 (JMP-2), page 1, respectively. Due to the nature of the Asset Relocations program, only projects known in advance in the LVD underbuild relocations investment category are listed. The Company developed the projected costs of the projects in this exhibit considering estimated costs for materials and labor and the Company's previous experience performing similar projects. These exhibits also identify the location of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Asset Relocations subprogram?

A. The Company is projecting LVD Asset Relocations capital expenditures of $168,109,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 12, column (k), and $131,401,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 12, column (l). The Company's historical actual spending in the LVD Asset Relocations subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 12, and below in Figure 16.

FIGURE 16
LVD ASSET RELOCATIONS SUBPROGRAM EXPENDITURES



Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 17 below.

FIGURE 17
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	$37,876,000	4,505	$29,148,000	3,379
LVD underbuild relocations	$9,443,000	N/A	$7,267,000	N/A
Make-ready work	$120,790,000	3,490	$94,985,000	3,026
Total	**$168,109,000**		**$131,401,000**	

Q. How did the Company develop its projected expenditures for customer requested and other internal relocations?

A. In the instant case, the Company is projecting that customer requested and other internal relocations will remain flat from their five-year historical average from 2021 through 2025,

plus inflation. The Company used an inflation rate of 2.9% for 2026, 2.5% for 2027, and 2.2% for 2028, which are also the inflation rates used for LVD Lines New Business.

Q. How did the Company develop its projected expenditures for the LVD underbuild locations investment category?

A. The Company anticipates a continued need for LVD lines to be relocated, proportional to the Company's work on the HVD system, to accommodate HVD projects, especially in the HVD Lines Reliability and HVD Lines Rehabilitation subprograms. The Company's projected expenditures in this investment category are based on what is needed to complete the LVD underbuild projects listed in Exhibit A-167 (JMP-1), page 1, and Exhibit A-168 (JMP-2), page 1. These projects were identified based on projected HVD expenditures, which are discussed by Company witness Kurt LaFrance. The Company's projected expenditures for LVD underbuild work are also in line with the historical average from 2021 through 2025.

Q. How did the Company develop its projected expenditures for make-ready work?

A. The Company is projecting that make-ready work will continue to increase in comparison to recent history, especially as telecommunications companies request installation of new cellular and broadband equipment on poles driven by federal grants and capital investment. Since 2022, increases in make-ready work have been driven by several government programs – Rural Digital Opportunity Fund ("RDOF") and the American Rescue Plan Act, which funded the Realizing Opportunity with Broadband Infrastructure Networks ("ROBIN") grant – to install broadband to rural homes. Going forward, the Broadband, Equity, Access and Deployment ("BEAD") program went through its application window for grant funding in 2025, and construction is set to start in 2026. The increased importance

of high-speed broadband is supported by large amounts of capital investment in the broadband industry. This program investment will significantly impact the LVD Asset Relocations subprogram through at least 2028.

When the Company performs make-ready projects, it recovers some of the costs from the requesting party, and the amount recovered is not part of rate base. In order to determine net make-ready expenditures, the Company projects how much it will recover in the future.

Q. Can you provide further detail on how make-ready work expenditures have been calculated for the instant case?

A. Figure 18 below documents the Company's make-ready work since 2021, with projections through 2028. This figure shows the total amount spent on the work, the underlying number of work orders, the amounts recovered by the Company, and the Company's cost share. The Company's cost share is the amount that the Company requests for recovery in a rate case.

FIGURE 18
MAKE-READY ACTUAL AND PROJECTED WORK

Year	Total Spending	Recovery	Percent Recovered	Company Cost Share	Make-Ready Field Complete Orders
2021 Actual	$12,377,903	$5,924,557	48%	$6,453,346	829
2022 Actual	$27,879,164	$13,305,056	48%	$14,574,108	1,236
2023 Actual	$37,496,781	$24,474,069	65%	$13,022,712	1,655
2024 Actual	$39,574,196	$19,151,261	48%	$20,422,935	1,640
2025 Actual	$71,438,983	$18,312,823	26%	$53,126,160	1,492
2026 Projected	$121,446,271	$31,576,030	26%	$89,870,240	2,526
2027 Projected	$138,448,749	$45,688,087	33%	$92,760,661	2,891
2028 Projected	$157,831,574	$58,397,682	37%	$99,433,892	3,296

Q. Please explain the variation in the percentage of costs recovered by the Company.

A. Through 2024, the Company typically recovered 48% of costs in a given year. In 2023, the Company has a temporarily higher recovery rate due to a temporary increase in reimbursement from attaching parties driven by extensive rural expansion. At the beginning of 2025, the Company instituted sound testing of poles as part of the engineering process for make-ready work, replacing deteriorated poles identified in this way; the Company did not previously do this as part of make-ready work. These pole replacements are not part of cost sharing, so the Company does not recover those dollars. Because of this testing, the Company replaced many more poles as part of make-ready work in 2025 than in earlier years. For example, in 2020, the Company replaced an average of 12 poles per order in make-ready work, and in 2025 this increased to an average of 20 poles per

order. The total number of poles replaced in make-ready work was about 50% higher in 2025 compared to 2024 totals. It is important to note that these pole replacements, by addressing deteriorated poles, will have a positive impact on customer reliability and safety.

These pole replacements have had a twofold impact on make-ready work. First, the total amount of spending has increased relative to the number of work orders. Second, as the percent recovered decreased, the Company's unit cost per work order has increased. The Company expects these trends to continue as the Company continues to identify deteriorated poles during sound testing for the next several years until all poles have been tested. In the instant case, the Company is projecting that recovery will once again be 26% in 2026, based on actuals year-to-date as of the time of filing. In 2027 and 2028, the Company projects to increase its recovery percentage back in the direction of historical levels, although the recovery percentage will not return to the level that prevailed prior to sound testing of poles.

Q. How does the Company substantiate the projected growth in total make-ready work?

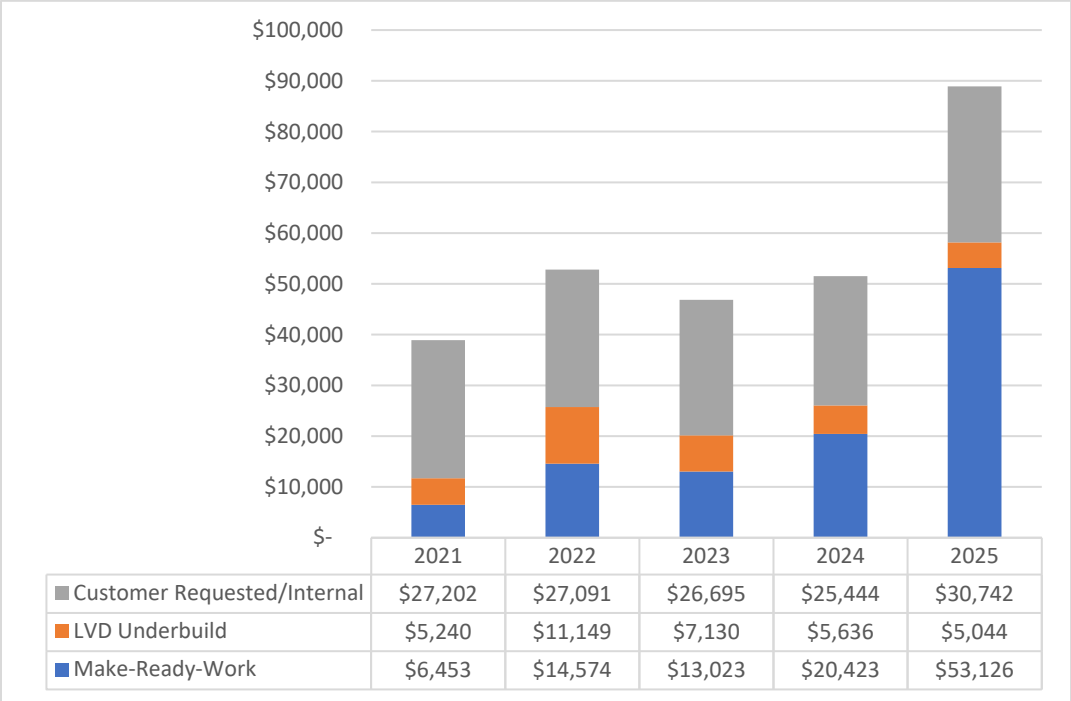
A. As noted above, the continued growth is substantiated largely by the rollout of the BEAD program in 2026, as funding is starting to be released. The Company has already seen an average of 26% year-over-year growth from 2022 through 2025 in its total work-hours to complete make-ready work orders primarily driven by capital investment in broadband. The Company is projecting a 70% year-over-year increase in 2026; as of mid-April 2026, the Company already had sufficient work orders for the 2026 calendar year to account for its 2026 calendar year projections in the instant case. The Company's work hours for make-ready work during the first quarter of 2026 were also commensurate with the projected

growth rate. In 2027 and 2028, the Company is projecting 14% increases in workload to account for continued capital investment in broadband and BEAD-driven growth; this amount is aligned with the slowest annual increase seen by the Company since 2022.

Q. What has been the historical actual spending in the LVD Asset Relocations subprogram for the past five years?

A. The Company's historical actual spending in the LVD Asset Relocations subprogram for the past five years is shown in Figure 19 by investment category.

FIGURE 19
LVD ASSET RELOCATIONS 5-YEAR HISTORY



	2021	2022	2023	2024	2025
Customer Requested/Internal	$27,202	$27,091	$26,695	$25,444	$30,742
LVD Underbuild	$5,240	$11,149	$7,130	$5,636	$5,044
Make-Ready-Work	$6,453	$14,574	$13,023	$20,423	$53,126

Q. Please explain the year-over-year variation in spending in this subprogram.

A. Because investment in this subprogram depends heavily on requests for relocation, the cost and amount of relocation projects can vary. In 2021, spending by the telecommunications companies was limited. Starting in 2022, telecommunication companies increased their spending, as discussed above, driving increases in make-ready spending. Additionally, the

Company needed to relocate a larger than normal number of LVD lines in 2022 to accommodate HVD projects, particularly in locations where LVD lines were underbuilt on HVD structures.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Unit costs for make-ready work were already addressed in my discussion of Figure 18. For other work, average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram, as there is a wide variance among work required.

Reliability Program

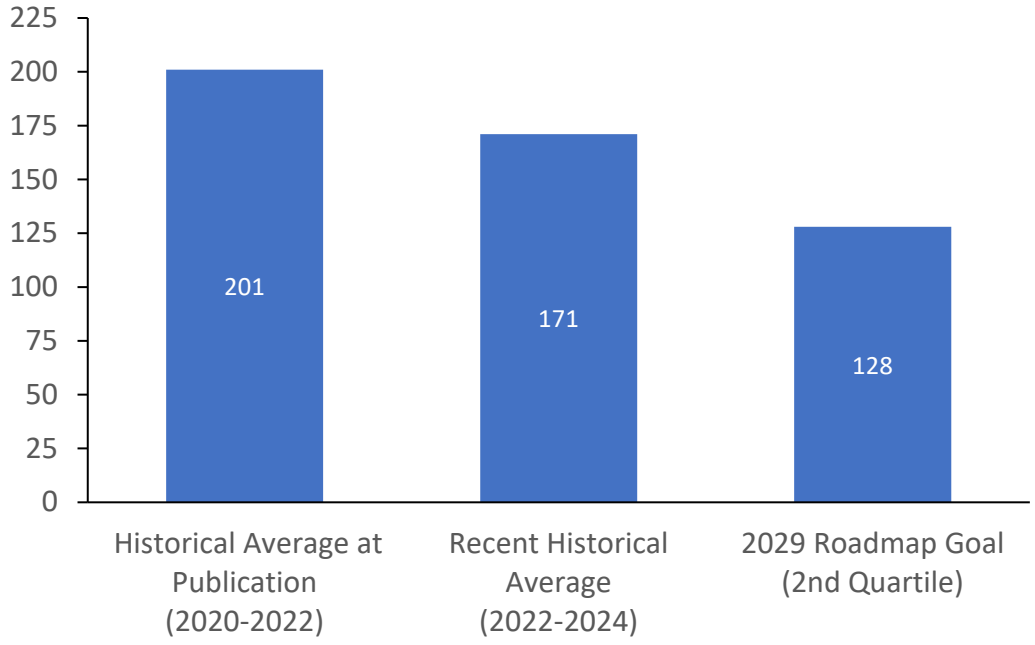
Q. What is the purpose of the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the electric distribution system, and to support the Company's SAIDI glidepath, as discussed by Company witness Duke. The Company developed the Reliability Roadmap by modeling different scenarios for increasingly severe weather and then defining a ramp-up in distribution system investment to improve reliability in the face of that worsening weather. That plan consists of four key categories of work: line clearing, hardening, inspections, and digital automation. As I will discuss in this section of my testimony, the hardening work largely takes place in the Reliability Program, particularly in the LVD Lines Reliability and Resiliency subprograms. In these subprograms, the Company is investing at higher levels than the historical levels that predated the Reliability Roadmap.

Q. Why has the Company been increasing Reliability investment compared to historical levels?

A. The Company's scenario modeling in the Reliability Roadmap indicated that climate change will result in more severe weather and extreme heat, in turn creating increasing reliability and resiliency challenges for the distribution system, with an increase in severe weather-related outages by the early 2030s, compared to 2020 levels. Furthermore, Company witness Duke explains that the Company's investments identified in the Reliability Roadmap are expected to deliver second quartile reliability performance by the end of the decade, as shown in Figure 20 below; absent these investment levels, the Company will not be able to deliver the reliability that both the Commission and various stakeholders have indicated is needed for customers.

FIGURE 20
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



Q. The Reliability Roadmap identifies a reliable and resilient system as one of the Company's distribution objectives. Is resiliency different from reliability?

A. Yes, but resiliency and reliability are related. *Reliability* is defined as the ability of the system to withstand normal variation and continue serving customers predictably. While reliability investments focus on the typical days of the year, when conditions are normal, resiliency investments are focused on storms and other extreme weather, which are only projected to become more frequent, as described by Company witness Duke. A resilient electric system yields reliable customer service by withstanding these extreme storms. While investments may initially target either reliability or resiliency, the outcome of the investment will often improve both.

Q. How do you define Resiliency?

A. The Company defines resiliency as the ability of the system to withstand a major event – particularly, a large and/or extreme storm – and the ability of the system to recover from a major event where damage occurs, minimizing the needed restoration and repair time.

Q. Are reliability and resiliency differentiated within the Reliability Program?

A. Among LVD Reliability Program investments, most subprograms are primarily focused on reliability improvements, targeting SAIDI reductions on blue-sky days. The Resiliency subprogram is focused primarily on resiliency investments, which may not result in major blue-sky SAIDI reductions, but are designed to harden the system and reduce the impact of major weather events on customer outages.

Q. How does the Company measure the benefits of Reliability program investments?

A. There are various means of measuring reliability benefits that will be discussed at various points in my testimony, but one of the most important is the customer-outage-minute benefit.

Q. What is meant by a customer-outage-minute benefit?

A. Customer-outage-minutes, sometimes shortened to customer-minutes or customer-minute interruption (CMI), is a mathematical product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes. These numbers are gathered through the Company's outage management systems for each outage. For example, a failure on the LVD system that interrupts electrical service to 100 customers for 170 minutes would accrue 17,000 customer-outage-minutes. A reliability project will reduce this number by either reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. The planning engineer will determine the amount of savings based on both the historical outage data of that part of the system and the expected effectiveness of the solution selected. For example, if the historical average customer-outage-minutes of an LVD zone was 20,000 per year and the proposed project would reduce the probability of that outage by 70%, the customer-outage-minutes avoided by completing the work would be 14,000 (70% of 20,000). In this way, the benefit of a distribution reliability project can be quantified.

Q. What portion of the Reliability Program will your testimony discuss?

A. My testimony will focus on the following LVD subprograms.

(i) LVD Lines Reliability;

(ii) LVD Repetitive Outages;

(iii) LVD Lines Rehabilitation; and

(iv) Resiliency.

Projected spending and benefits are explained in detail in the subprogram sections below.

LVD Lines Reliability

Q. What is the purpose of the LVD Lines Reliability subprogram?

A. The LVD Lines Reliability subprogram includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. The subprogram includes a diverse range of projects that are designed to address concerns on a given circuit or circuits.

Q. How does the Company identify LVD Lines Reliability projects?

A. The Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize reliability issues. The analyses used help identify specific areas to target investments based on probability of future issues and help prioritize projects that will deliver the greatest reliability improvements.

Q. What is the primary input in this process?

A. The primary input for deciding where to invest is data provided by the Reliability Analytics Engine ("RAE"). The RAE data is used to help the Company evaluate how to maximize the reliability benefit to customers through reduced outages.

Q. Please describe the RAE.

A. The RAE is a database used to analyze outage incident history and electric operations performance. The RAE arranges multiple data points in a manner that allows key reliability metrics (e.g., System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Customers Experiencing Multiple

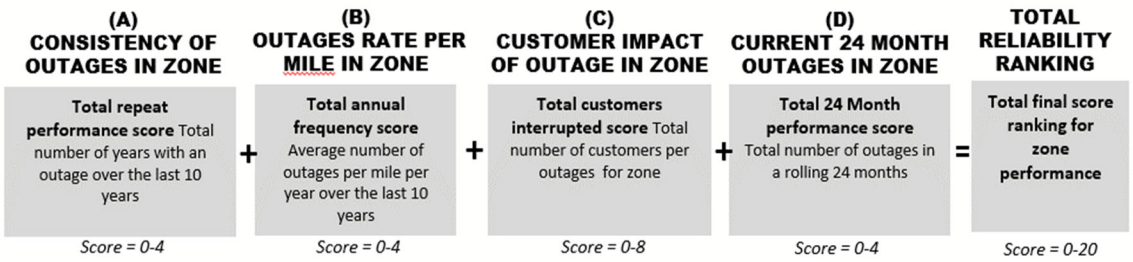
Interruptions ("CEMI")) to be calculated at varying levels of granularity. By combining data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps, and calculates the time spent in each step. The RAE also includes other sources such as line clearing data, callout success rates, and historical project spending. These can be combined with other data to analyze reliability. The RAE also produces monthly zonal analysis data that is reviewed by each area's LVD circuit planner. This data is analyzed to determine zonal impact to LVD system reliability.

Q. What conclusions does the Company draw from this RAE analysis?

A. By analyzing historical outage data across the LVD system, identifying trends, and assessing zones with the greatest potential for reliability improvement, the RAE provides a ranking of zones to target to maximize SAIDI reduction. Data is analyzed in four ways —consistency of outages, outage rate, customer impact, and current year outages—to determine the score for any given zone compared to all other zones on the LVD system statewide.

The results of the analysis are totaled to determine the final score for any given zone, as shown in Figure 21. The RAE zone scores are recalculated as new outage events occur, allowing the analysis and resulting rankings to continuously reflect updated reliability conditions across the LVD system.

FIGURE 21
ZONAL RANKING FORMULA



Q. Does the Company consider anything besides RAE output when prioritizing projects?

A. The RAE is one tool – albeit a tool that pulls in many diverse types of data – that helps create a zonal health score that then informs prioritization of zones. The zonal health score considers important factors in prioritizing reliability zones, including consistency of outages in the zone, outages rate per mile in the zone, customer impact of the outages in the zone, and the current 24-month outages in the zone. Thus, the Company uses the zonal health score to identify customers that are experiencing the poorest reliability and prioritizes zones to trigger projects to improve reliability for those customers. But this is only a reliability input that is used to identify targeted zones on the LVD system. For each zone, multiple project alternatives are developed, evaluated, and prioritized to create an investment plan that maximizes customer reliability benefits. Each zone undergoes a review of several feasible options, and the alternative that provides the greatest benefit—or the most viable option without significant barriers—is advanced. Barriers that may necessitate selecting a lower cost-benefit option include EGLE permitting requirements; substantial wetland mitigation costs; river, wetland, highway, or railroad crossings; and customer easement refusals.

Q. How does the Company determine which alternative provides the greatest benefit?

A. The best use of Company resources is for the Company to seek to address those areas that are experiencing the poorest reliability. The Company typically does this on a "least-cost-best-fit" basis, which is commonly recognized in the industry as an appropriate means for evaluating reliability investments. Least-cost best-fit analyses consider the desired functionality or capability on the distribution system, or the safety, reliability, or regulatory goals, along with the lowest cost way to accomplish these goals.

Q. Why does the Company utilize least-cost-best-fit analyses for this sub-program?

A. The Company recognizes that interruptions to customers is a problem worth solving. Using least-cost best-fit to select the method for addressing reliability concerns is preferrable to relying on cost-benefit ratios, which could result in concluding that a project that does not pass a certain threshold is not worth completing, thus leaving the problem of those customer interruptions unaddressed.

Q. What other information does the Company consider when identifying potential LVD Lines Reliability projects?

A. The Company considers other circuit characteristics, such as car-pole accident history and downed wires, to potentially add or reprioritize the list of projects. In addition, the Company uses advanced metering infrastructure ("AMI") data to identify voltage deviations on the circuit, and to create projects to ensure service to customers is delivered within the voltage range specified in Company tariffs.

Q. What investment categories are included in the LVD Lines Reliability subprogram?

A. The LVD Lines Reliability subprogram consists of five investment categories:

(i) targeted circuit improvements;

(ii) pole replacements;

(iii) ATR loops;

(iv) circuit exit enhancements; and

(v) ROW and easement acquisition.

Targeted Circuit Improvements

Q. What does the Company include in targeted circuit investments?

A. Targeted circuit improvements include several project types with customized solutions to address specific reliability concerns. The Company employs four distinct strategies within this investment category including:

(i) reducing the amount of non-standard voltage on the distribution system;

(ii) zonal health investments;

(iii) converting open-wire secondary and services to multiplex; and

(iv) rejuvenating vintage underground cable.

The Company has been doing some amount of the types of work contained in each strategy for many years, but only began calling out each strategy separately in Case No. U-21585, following the language used in the 2023 filing of the Reliability Roadmap. This allows the Company to provide more detail and transparency around the diverse types of work in the targeted circuit improvement investment category than was provided in earlier electric rate cases.

Reducing Non-Standard Voltage

Q. How does the Company reduce the amount of non-standard voltage?

A. Non-standard voltage conversion is discussed in the Reliability Roadmap. The Company converts distribution circuits and substations energized at non-standard voltages to one of

the three standard voltages that Consumers Energy operates. The Company presently operates 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV grounded-wye. Systems dedicated to serving a single customer site are not within the scope of this category.

Q. Are there additional benefits of reducing the amount of non-standard voltage beyond improving reliability?

A. Yes. First and foremost, reducing the amount of non-standard voltage provides safety benefits, as described in the Reliability Roadmap and as discussed by Company witness Duke. Also, in addition to improved reliability through customer-outage-minute savings, further benefits include:

- Reduced system losses and increased system line capacity – Converting delta systems to grounded-wye reduces load current on primary lines, thereby increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the delta system carries (e.g., a 400 Amp rated conductor carrying 360 delta Amps (90% loaded) will carry 208 wye Amps (52% loaded) after the conversion). Since the amount of loss in an electric system is proportionate to the square of the load current, reducing the load current by voltage conversion lowers the electric loss associated with that portion of the electric system. Further loss reduction is typically realized through voltage conversion as older transformers and isolators are replaced as part of the voltage conversion project.

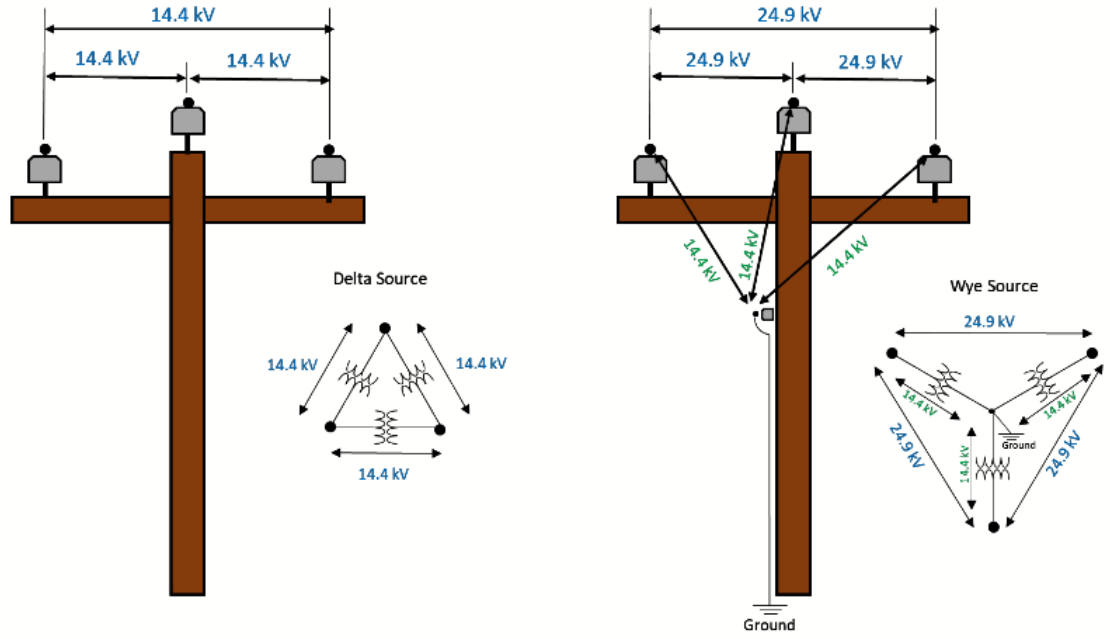
- Reduced number of interrupted customers for single-phase faults – When a single-phase fault occurs on the delta system, two primary phases are disrupted, interrupting two-thirds of the customers; when a single-phase fault occurs on the grounded-wye system, only one phase trips, interrupting one-third of the customers.

- Increased system load transfer capability – Circuit conversions create the opportunity to improve transfer capability between like systems and build a platform for increased distribution automation and smart grid systems. This is essential for Distribution Automation and FLISR, which are discussed by Company witness Scott McPhail.

- Reduced equipment inventory – Eliminating the non-standard line transformer inventory would reduce and eventually eliminate the need to maintain non-standard line transformer inventory. Non-standard transformers are more

difficult to maintain in inventory in sufficient quantities, because suppliers produce fewer of them. The Company experienced a shortage of transformers, exacerbated by the need for non-standard voltages, in the past couple of years, leading to delays in connection of new customers.

FIGURE 22
ILLUSTRATION OF DELTA VS. WYE CONFIGURATIONS



Zonal Health Investments

Q. What are zonal health investments?

A. Zonal health investments are addressed in the section of the Reliability Roadmap on LVD circuit health. The Company's analysis of all weather conditions (i.e., including major event days) has shown that 97% of primary line customers experiencing interruptions happen on just 25% of primary line miles. This analysis is one input that is fed into the RAE tool to prioritize zones. Because of this, the Company focuses on or "targets" individual zones when assessing LVD asset health and mitigating the risk, instead of whole circuits. The Company assesses the health of each zone using the zonal health assessment

rubric that is explained in the Reliability Roadmap and Figure 21 earlier in my direct testimony.

Q. When did the Company begin doing zonal health improvement work?

A. The Company began doing zonal health improvement work in 2013.

Q. Can you provide some illustrative examples of how zonal health investment projects are selected?

A. Test period examples include:

- Whitehall Substation, Alice Circuit, LCP 874 has a zone score of 19. The zone has experienced five outages over the past 24 months and serves approximately 305 customers. The project is to replace existing open-wye conductor with single phase and three phase 1/0 tree resistant wire at key locations within the zone totaling ~0.5 miles. In addition, the project will upgrade an existing fuse to a recloser, install additional lateral fusing, and rebalance load across the three phases. These improvements will reduce vegetation-related outages, improve circuit protection and sectionalizing, and enhance overall reliability by limiting customer exposure during outage events. This project was selected due to the high zone score, recent outage history, customer exposure, and the reliability benefits provided by conductor upgrades, improved protection, and phase balancing. Replacing with bare conductor and a reduced-scope alternative was also considered but not pursued, as it would not provide a complete, end-to-end reliability solution.

- Keating Substation, Laketon Circuit has a zone score of 18. The zone serves approximately 771 customers and has experienced an increased number of outages, primarily due to vehicle-to-pole accidents. The affected zone is approximately 1.0 miles in length and is located in an urban and industrial area adjacent to East Laketon Avenue where it crosses US-31. Due to the presence of businesses and industrial customers along the route, relocating the line further from the roadway is not feasible. The selected project is to reconductor approximately one mile of the zone with 336 kcmil aluminum conductor steel reinforced ("ACSR"), remove unneeded poles to reduce roadside exposure, and upgrade pole class to harden the line against vehicle impacts. These improvements will reduce the likelihood of car-pole accidents, which are the primary cause of outages in this zone. In addition, the upgraded conductor will increase circuit capacity to support a planned automation loop and improve protective device reach by increasing available fault current. This project was selected due to the high zone score, outage history driven by roadway exposure, customer impact, and the reliability benefits provided by targeted hardening and capacity improvements. Undergrounding was evaluated but not selected due to

cost, constructability challenges within a dense urban corridor that includes double-circuit construction on a shared pole line, complex easement requirements, the presence of large industrial load customers, and multiple major road crossings. Partial hardening alternatives were also considered but were not selected, as they would not have adequately addressed the primary outage drivers within the zone.

- North Park Substation, Lamberton Circuit has a zone score of 18. The first zone out of the substation serves approximately 2,712 downstream customers and experienced multiple circuit lockouts in 2023 and 2024, impacting more than 2,700 customers during each event. Most outages were caused by tree contact and public damage. Based on the repeated customer impacts and elevated zone score, this zone was selected for a zonal health improvement project. The project includes reconductoring approximately 0.7 miles of line with higher capacity aluminum conductor steel reinforced ("ACSR") conductor, replacing existing conductor from the tree line at 4 Mile Road and Brandau Drive to 4 Mile Road and Dean Lake Avenue. In addition, approximately 500 feet of open-wye secondary will be replaced in accordance with current standards, substandard poles and transformers will be replaced, and targeted tree trimming will be performed to improve crew access. These improvements are expected to reduce vegetation-related outages, improve circuit reliability and durability, and limit the frequency of large-scale customer interruptions in a zone with a high concentration of residential customers. This project was selected due to the high zone score, repeated large customer impact outages, and the opportunity to address multiple reliability drivers within a single zone. Undergrounding was considered but not selected due to cost, easement and terrain constraints, as well as high and concentrated electrical loading that would have required larger-than-typical underground facilities. Reduced-scope alternatives were not pursued because they would not sufficiently mitigate the risk of large customer impact events.

- Leland Substation, Leland Circuit, LCP 240 has a zone score of 17 and serves approximately 83 customers. The zone has experienced six outages in 2025 and three outages in 2024, indicating declining reliability performance despite the relatively low customer count. The affected zone is approximately 0.5 miles in length and is constructed with vintage # 6 copper conductor, which is undersized relative to current loading and no longer meets present design standards. The selected project includes hardening the line by replacing the existing conductor with 336 kcmil aluminum conductor steel reinforced (ACSR), installing new, larger, more robust poles, and replacing all substandard equipment along the segment. The line is adjacent to mature trees, and the area will be evaluated by Forestry prior to construction to identify removals necessary to reduce vegetation-related risk. These improvements will increase structural strength, improve conductor capacity, reduce the likelihood of vegetation- and equipment-related outages, and enhance overall reliability for customers served by the zone. This project was selected based on the elevated zone score, recent outage history, condition and vintage of existing

infrastructure, customer exposure, and the reliability benefits provided by targeted hardening and equipment replacement. Partial conductor or equipment replacements were evaluated but not selected, as a comprehensive rebuild was necessary to achieve a durable, first-time quality reliability outcome.

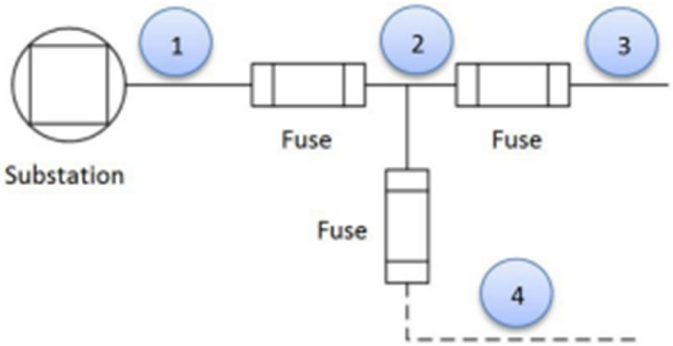
- Kent City Substation, Casnovia Circuit, LCP 703 has a zone score of 17 and serves approximately 568 customers. The zone has experienced a history of vegetation- and weather-related reliability issues, including ten tree- or weather-related outages since January 2021, contributing to the elevated zone score. The selected project includes reconductoring several targeted segments within the zone to address known vegetation exposure and improve circuit resiliency. Approximately 1,150 feet of existing 1/0 ACSR conductor will be replaced with 795 aerial spacer cable along Fruit Ridge Avenue, with additional short segments of conductor upgraded in other areas of the zone. The project also includes replacing existing 1/0 ACSR with 336 tree wire at select locations along Kenowa Avenue and at an intersection with recurring vegetation exposure. A forestry evaluation and targeted tree trimming will be performed prior to construction as needed to further reduce vegetation risk. These improvements will reduce tree-related outages, improve performance during severe weather events, and enhance overall reliability for customers served by the zone. This project was selected based on the elevated zone score, documented history of vegetation-related outages, customer impact, and the reliability benefits provided by targeted conductor upgrades and vegetation mitigation. Undergrounding was considered but not selected due to easement and terrain challenges and cost.

- Montague Substation, Dowling Circuit, LCP 211 has a zone score of 17 and serves approximately 427 customers across a zone that is approximately 3 miles in length. The zone experienced five outages in 2023 and 2024, most of which were attributed to tree contact originating outside of established pole line trim standards, indicating increased exposure to vegetation related reliability risk. The selected project includes upgrading the existing backup protection by replacing an aging oil based recloser with a modern electronic recloser, enabling improved coordination and the conversion of downstream switching locations to protective, coordinating fusing. In addition, the project includes upgrading portions of the existing bare conductor to 336 kcmil tree resistant wire to reduce the likelihood of vegetation related faults. These improvements will enhance circuit protection coordination, reduce customer exposure during tree related outage events, and improve overall reliability within the zone. This project was selected based on the elevated zone score, recent outage history, customer impact, and the reliability benefits provided by improved protection and targeted conductor hardening. Protection-only or conductor-only alternatives were evaluated but not pursued, as an integrated approach was required to provide a durable and complete reliability improvement.

Q. Can you provide an illustration of how circuits are subdivided into zones?

A. Yes. Please refer to Figure 23 below, which shows a circuit subdivided into four zones. The Company has approximately 154,000 protective zones on its LVD system.

FIGURE 23
ILLUSTRATION OF PROTECTIVE ZONES



Q. How do zonal health investments create benefits for customers?

A. Zonal health investments improve the reliability of the Company's LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone targeted for improvement can include multiple protective device zones or a single protective device zone. When the Company is aware that a circuit has deficiencies, based on outage data, then the Company inspects the overhead lines on affected circuits to identify appropriate solutions to improve reliability on those circuits. Solutions in zonal health investments include, but are not limited to:

- Replacing equipment at the end of expected life, including poles, cross-arms, switches, and conductor (overhead and underground);
- Installing new system protection devices, including fuses, switches, and reclosers to reduce the size of the zone, and to reduce the number of customers impacted by an interruption (see Figure 24 for an illustration of this work);
- Installing upgraded poles and composite cross arms to meet increased design and construction standards;

- Upgrading conductor at risk for contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection. Both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and associated interruptions;

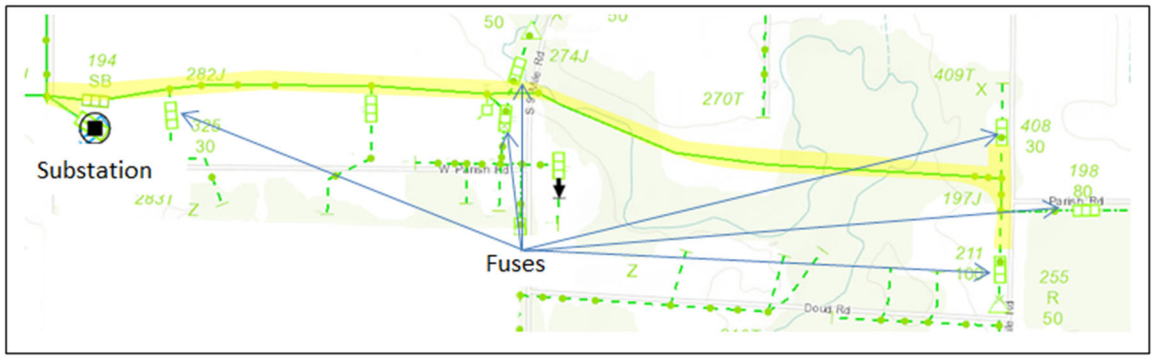
- Restoring underground cable that is no longer looped to re-establish redundancy;

- Improving system protection coordination and reach – following certain upgrades, protective devices may no longer coordinate (a systematic application of devices to ensure clearing of permanent faults) or reach (the zone or area of protection in which a fuse, recloser, or breaker will open within an acceptable timeframe);

- Improving the system's capability to isolate and transfer load for improved restoration time; and

- Improving voltage quality through equipment upgrades, reconductoring, circuit reconfiguration, and phase balancing.

FIGURE 24
ILLUSTRATION OF ZONE PROTECTION DEVICES



Q. Has the Company adjusted its LVD Lines Reliability approach?

A. Yes. As described earlier in the LVD Lines Demand Failures section, the Company took a new approach to LVD overhead line assessments in 2022, including the addition of high-value lateral fusing. This decreases SAIDI by isolating future faults to smaller sections of line, minimizing the number of customers affected per interruption, and minimizing the amount of time required for LVD line crews to patrol and identify the cause of the outage. EPRI validates this approach in their technical report, *Distribution Grid Resiliency:*

Prioritization of Options[2], Appendix D, page 13, noting that "[a]pplying sectionalizing devices can reduce sustained interruptions per mile by reducing the number of customers who are outaged by the initial event. Only those customers downstream of the protective device nearest the fault location are affected."

Q. Can the Company demonstrate the benefits of zonal health investments?

A. Yes. The Company has measured the performance of circuit improvement projects by comparing the three years of outage history of the zone prior to investment to the outage history for the one to three years after investment. Zonal health improvement work has produced, on average, a 45% reduction in outages. Figure 25 illustrates zonal performance improvements following targeted circuit improvement projects in 2019 through 2025.

FIGURE 25
AGGREGATED IMPACT OF TARGETED CIRCUIT IMPROVEMENTS ON ZONAL PERFORMANCE

Project Year	Zonal Projects	Prior 3-Year Average Outages	Post 1-Year to 3-Year Average Outages	Percent Improvement
2019	151	280	94	66%
2020	146	206	59	71%
2021	249	347	132	62%
2022	1,394	199	128	35%
2023	2,884	274	192	29%
2024	2,068	796	744	6%
Weighted Average Improvement				**45%**

[2] *Distribution Grid Resiliency: Prioritization of Options*, https://www.epri.com/research/products/3002006668

Q. Can you discuss the trend in percentage improvement following targeted improvement projects?

A. When interpreting Figure 23, it is important to note that the "zonal projects" column includes fusing work in 2022, 2023, and 2024, in addition to more traditional zonal health improvement work, which is why the number of projects increases by so much. Fusing projects do not necessarily reduce the number of outages on a circuit, but they do reduce the number of customers impacted by any particular outage. This impacts the before and after outage numbers in the figure, and therefore the calculated percentage improvement. It is important to note that traditional zonal health improvement work delivers substantial outage reduction benefits, as shown in the data from 2021 and earlier, when those traditional investments made up the large bulk of these projects. These traditional investments continue to take place even as large amounts of fusing work have taken place as well.

Q. Please provide some specific examples of recent zonal health improvement projects.

A. Recent examples of these projects include:

- **Alger Substation, Skidway Circuit** experienced 9 outages in 2024, affecting approximately 2,000 customers. The project addressed reliability and safety concerns along a 2-mile section of line with historical exposure related to conductor configuration and vegetation risk. The scope of work included reconductoring the existing line to 336 kcmil aerial spacer cable, which improves reliability and reduces vegetation-related outage risk. In addition, the project removed a double-circuit line with two separate voltage levels, eliminating added safety risks for crews, patrol time during outages, and equipment overloads that could occur if conductors become entangled. These improvements increase circuit resilience, enhance worker safety, and reduce customer exposure during outage events. The project is expected to save approximately 789,419 customer outage minutes. Additionally, this zone has not seen an outage since the project was completed in late 2025 and remained energized during the ice storm in March 2026 while the zone northeast was impacted by the ice. A reduced-scope alternative that would have removed only the lower-voltage circuit and added additional isolators was evaluated but not

selected, as it would have retained mixed voltages and additional devices that increase outage risk and would not have fully addressed the underlying reliability and safety concerns.

- **Cedar Springs Substation, Edgerton Circuit** serves approximately 990 customers and experienced four outages across 2023 and 2024 along a 1.5-mile section of line. The outages were associated with vegetation contact and limited circuit sectionalizing. In 2024, the Company reconductored the existing line from smaller-capacity bare wire to larger-capacity 336 kcmil aluminum conductor steel reinforced ("ACSR") tree-resistant wire. In addition, a Viper recloser was installed to sectionalize the circuit, dividing the zone into two sections. These improvements reduced vegetation-related outage risk, increased circuit capacity, and limited customer exposure by reducing the number of customers affected during outage events. These improvements are expected to save approximately 2,073,212 customer outage minutes. Undergrounding was considered but determined to be cost-prohibitive due to extensive easement requirements, and a protection-only upgrade was not selected because it would not have addressed the condition of the existing conductor or long-term reliability risks.

- **Honor Substation, Indian Hill Circuit, LCP 6418** experienced six outages across 2023 and 2024, interrupting approximately 128 customers. The affected section consisted of 1.2 miles of single-phase line located in deep right-of-way and constructed with vintage #6 copper conductor, which is more susceptible to damage during storm events. In 2024, the Company relocated the line to a roadside location and reconductored with 1/0 aluminum conductor steel reinforced ("ACSR"). In addition, fusing was installed on all laterals to ensure proper isolation during fault events. Relocating the line improved access for maintenance and restoration, enhanced crew safety, and reduced outage duration, while the new conductor and added fusing improved reliability by limiting the number of customers impacted during outages. These improvements are expected to save approximately 59,826 customer outage minutes. Undergrounding was considered but not selected due to extensive easement requirements, challenging terrain with mature tree root systems, limited ROW and ground conditions that made the option impractical and costly.

FIGURE 26
LVD TREE-WIRE CONSTRUCTION SUPPORTING A FALLEN TREE



Q. Are there specific benefits to projects that add lateral fuses?

A. Yes. The Company's analysis of lateral fuse additions completed in 2022 shows that these fuses prevented 43 circuit lockouts and avoided approximately 4.6 SAIDI minutes, excluding MEDs, in 2022. The lateral fuse additions completed have avoided approximately 5.4 SAIDI minutes, excluding MEDs, in 2023, 6.5 minutes in 2024 and 6.22 minutes in 2025. Continued addition of lateral fuses in 2026 will further reduce SAIDI.

Q. Does the Reliability Roadmap define a long-term workplan for zonal health investments?

A. Yes. In the Reliability Roadmap, the Company explains a plan to address all zones with a zonal health score of 10 or greater, meaning each of these zones will need investment. The 2023 Reliability Roadmap provided a plan to do this work over a period of 20 years, with a ramp-up in investment to addressing approximately 280 zones per year. However, in 2025 the Company adjusted this plan to maintain its SAIDI glidepath while accounting for increased line clearing work, and the Company is now intending to target approximately 85 zones per year (this increased line clearing work is tied, in part, to recommendations from Liberty Consulting Group ("Liberty") in their audit of the Company's distribution system, filed in Case No. U-21305 in September 2024). In every instance, the Company is planning projects in zones that have been specifically identified as needing investment to deal with reliability issues.

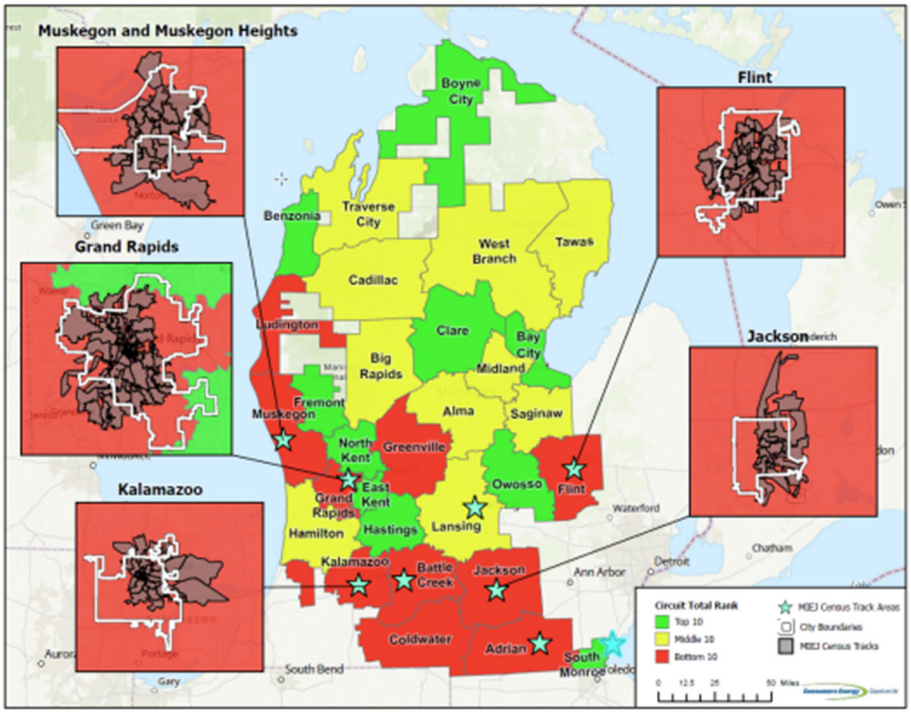
Converting Open-Wire Secondary and Services to Multiplex

Q. What are the issues facing secondary conductor on the Company's distribution system?

A. As discussed in the Reliability Roadmap, secondary assets—located between the distribution transformer and customer meter—are more challenging to repair than primary assets. This challenge is most prevalent on open-wire secondary, much of which is approaching the end of its life, and is brittle and not easily repaired, and thus is more vulnerable to tree damage. Individual outages on the secondary system may not affect large numbers of customers, but they are high-frequency and long in duration. As

demonstrated in Figure 27 below, open-wire secondary has a disproportionately high impact on vulnerable communities.

FIGURE 27
SERVICE CENTER REGIONS WITH SECONDARY CIRCUIT PERFORMANCE



Q. How does the Company plan to address these concerns?

A. As explained in the Reliability Roadmap, the Company plans to programmatically convert its open-wire secondary to multiplex secondary, focusing on circuits with the highest risk scores, while ensuring equitable investments into vulnerable communities. The targeted secondary circuits in the instant case are included in the project list in Exhibit A-167 (JMP-1), page 14; and in Exhibit A-168 (JMP-2), page 6. In Case No. U-21585, the Commission approved one half of the Company's initially proposed investment in open wire secondary conversion, which equated to approximately $14.4 million per year. The Company proposed to maintain this level of investment in Case No. U-21870, which was approved, and the Company's proposed investments in the instant case are in line with this

approved level. The Company's planned investments include a focus on vulnerable communities, with 33% of planned mileage in 2026 being on circuits serving census tracts with MiEJScreen scores in the 80th percentile or higher ("EJ circuits"). The difference between open-wire secondary and multiplex secondary is shown in Figure 28 below.

FIGURE 28
MULTIPLEX VS. OPEN WIRE SECONDARY



Q. How does this conversion work benefit customers?

A. The most important benefit of this work is to improve safety by reducing the occurrence of difficult-to-repair wire downs, particularly in vulnerable communities.

The new multiplex secondary will also have more capacity, reducing the number of future upgrades that would be needed when customers adopt new technologies, such as heating electrification or electric vehicle ("EV") charging, again helping customers in vulnerable communities to better access those opportunities. Typical open wire on the secondary system is able to carry between 95 Amps and 175 Amps, while multiplex is rated for 195 Amps to 320 Amps. For homes with 200 Amp panels, open-wire secondary may be approaching maximum capacity, which will not allow future growth for technologies such as EVs, electrification, and distributed energy resources ("DERs").

While the impact to systemwide SAIDI is modest, the outage duration benefits for the impacted customers will be more substantial.

Vintage Underground Cable Rejuvenation

Q. What are the issues facing vintage underground cable on the Company's system?

A. Vintage underground cables are discussed in the Reliability Roadmap. While underground distribution provides many benefits, particularly for resiliency, the cable eventually begins to degrade, which leads to a heightened risk of failure. This is a particular issue for 15 kV vintage cable that dates to earlier than the 1980s, which makes up approximately 2,500 miles of the 9,500 miles of underground primary cable on the Company's system. This vintage cable is also unjacketed, leaving the neutral conductors exposed to accelerated deterioration from exposure to soil and moisture. Figure 29 below illustrates the locations of this 15 kV vintage underground cable, along with locations of outages over the past three years. Figure 30 illustrates the SAIDI contribution of the underground system by location.

FIGURE 29
UNDERGROUND CABLE: LOCATIONS OF 15 KV CABLE

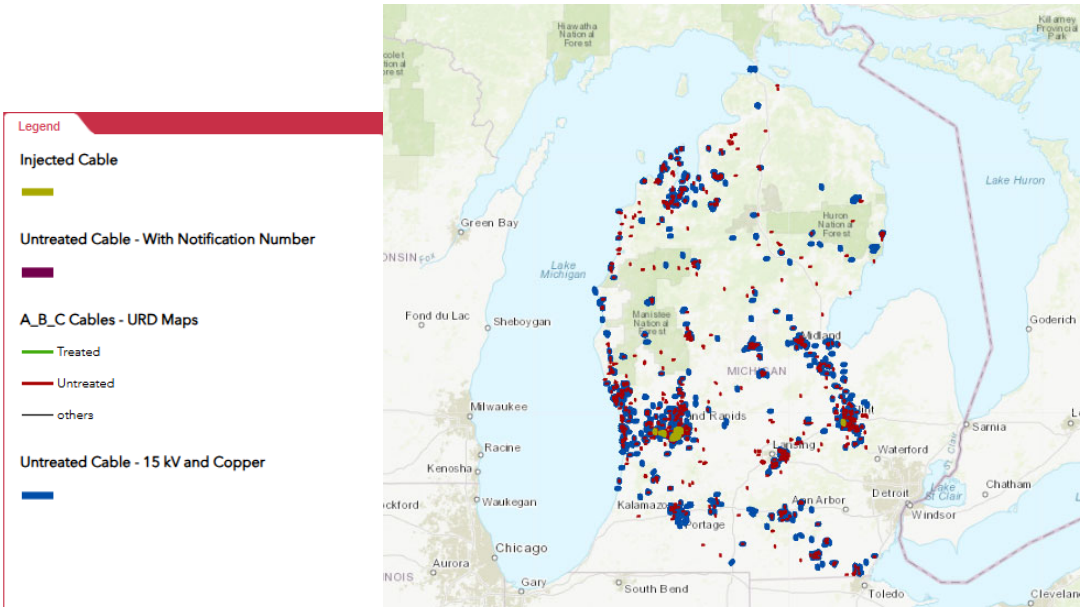
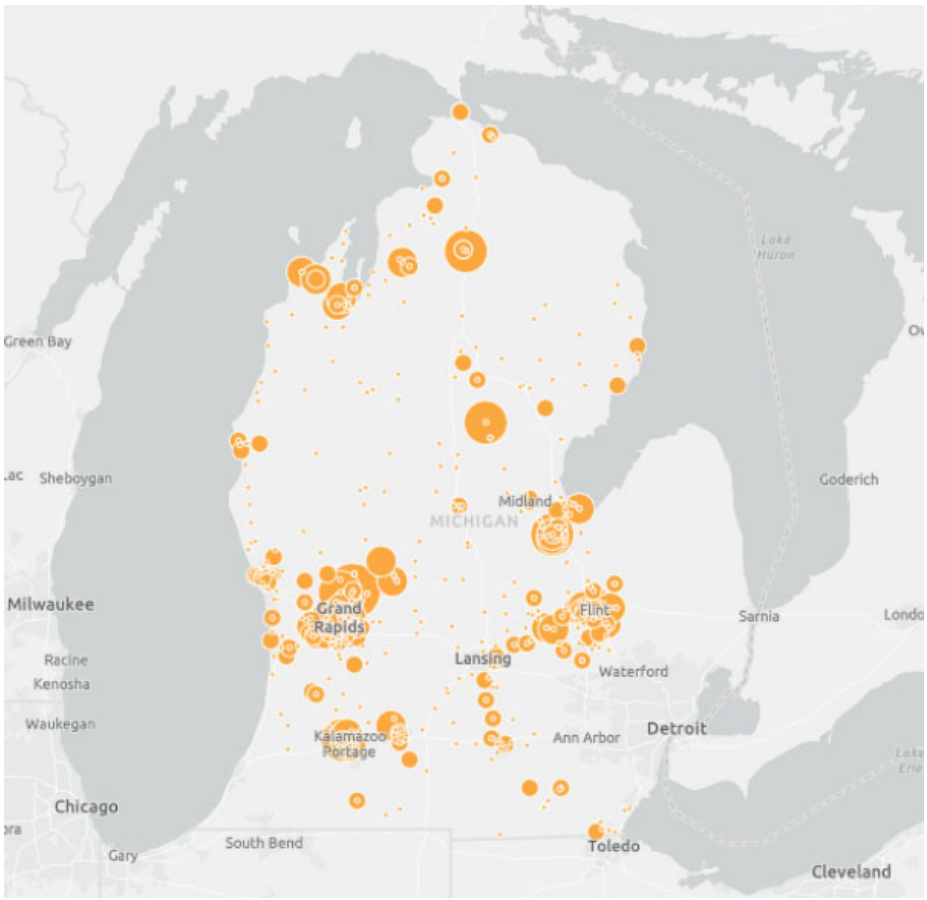


FIGURE 30
SAIDI CONTRIBUTION OF UNDERGROUND PRIMARY



Q. How does the Company plan to address these concerns?

A. Since 2018, the Company has used underground cable injection as one approach to rejuvenate deteriorated cable and prolong its useful lifespan by a minimum of 25 years. This process involves injecting a fluid insulation into the cable that then solidifies, and it can be less expensive than completely replacing the cable. In its early years of using this technology, the Company concentrated these investments in relatively limited applications in Grand Rapids. When the Company filed its Reliability Roadmap in 2023, and when the Company updated the Reliability Roadmap in 2025, it outlined a plan to scale up underground cable injection to rejuvenate all 15 kV cable installed between the 1960s and 1980s, over a period of nine years beginning in 2025.

However, the Company's efforts to begin this ramp-up in 2025 met with challenges. In order to successfully complete an injection, the Company must (a) convert transformers from live-front to dead-front; (b) locate any splices in the cable and remediate them; and (c) conduct significant pre-testing to determine if injection is feasible. When the Company was doing fairly limited injection work, these requirements were manageable. However, in attempting to significantly scale up its injection workload, these challenges imposed constraints on how much work could be done. Consequently, the Company determined that the scale of underground injection proposed in the Reliability Roadmap would be difficult to attain cost-effectively, and in the instant case the Company is proposing to scale back the amount of underground injection performed. By doing this, the Company can focus on underground cable segments with the highest likelihood of successful injection.

The Company will conduct further evaluation of how to address other 15 kV underground cable that is near end-of-life. On a preliminary basis, the Company expects that the most cost-effective means of addressing much of the cable on the system will simply be to replace it.

Pole Replacements

Q. What are the challenges currently facing LVD poles on the Company's system?

A. The Company's LVD system includes over 1.5 million poles, and a significant proportion of these poles are in a deteriorated or end-of-life condition and must be replaced. Pole replacements in the LVD Lines Reliability subprogram are identified based on the Company's dedicated program to perform groundline inspection of poles, or based on general overhead inspections that have identified poles in need of replacement.

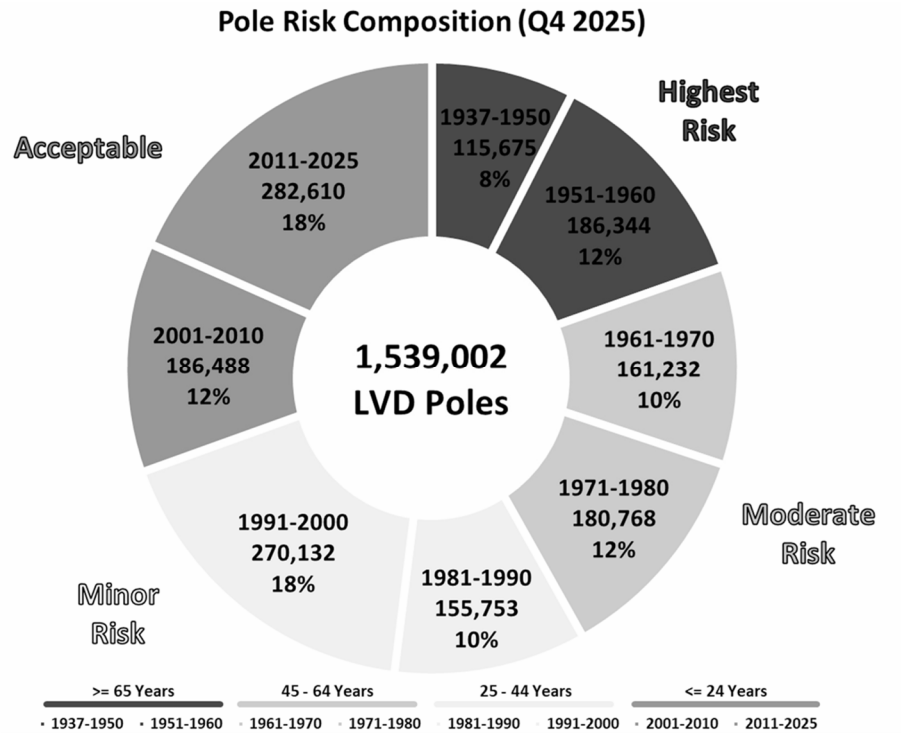
Q. What is groundline inspection of poles?

A. As specified in the Reliability Roadmap, the Company plans to replace all rejected poles identified either through a groundline inspection on a 12-year cycle or through the regular two-year visual inspection cycle of whole circuits. Based on system data, the Company initially estimated that approximately 10% of LVD poles will be classified as rejected through these inspections, resulting in an estimated 12,500 pole replacements per year. This anticipated rejection rate was based on known data about the vintage of poles on the Company's system, and the typical rejection rates of poles of a given vintage as supported by industry benchmarking data. A breakdown of the Company's pole vintage is shown in Figure 31 and a breakdown of LVD pole risk is shown in Figure 32. The highest risk poles carry a rejection rate of 15% or greater, and moderate risk poles carry a rejection rate of 10% to 15%.

FIGURE 31
LVD POLE VINTAGE BREAKDOWN

Vintage	Count	Percentage
2001-2025	469,098	30.48%
1981-2000	425,885	27.67%
1961-1980	342,000	22.22%
1960 and older	302,019	19.63%

FIGURE 32
LVD POLE RISK BREAKDOWN – Q1 2024



Q. What has the Company experienced to date with rejection rates from its groundline inspections?

A. In 2025, after testing 50,000 poles in two of the Company's eight geographical operation zones, the observed rejection rate was 6.4%. For the instant case, the Company is applying an expected failure rate of 8%, while also expanding inspections to 125,000 poles in 2026 to further refine the accuracy of this estimate. The Company believes that using an 8% failure rate is a reasonable reduction of the initially estimated 10% rate. The 6.4% result is based on a relatively limited early sample of poles inspected – relative to the size of the Company's system, with over 1.5 million poles – and has not been determined to be representative of the entire system.

Using an 8% failure rate and increasing annual inspections to 160,000 poles starting in the test period (yielding an expected 12,500 to 13,000 poles replaced annually), the

Company could complete the full assessment of the 1.5 million-pole LVD system in approximately 10 years—rather than 12—thereby reducing the risk of in-service pole failures.

Additionally, the Company is using data analytics to better prioritize the circuits with the highest-risk poles on its system using both external and internal factors, including soil conditions, weather patterns, pole type, and industry benchmark data. By addressing these highest-risk poles first, the Company anticipates a higher observed failure rate going forward in the early part of the inspection cycle.

Q. How do customers benefit from pole replacements?

A. The replacement of a pole prior to failure avoids the interruption of electrical service to customers and is considerably less expensive than replacing a pole after it has already failed.

In addition to reliability benefits, replacing poles prior to failure delivers significant benefits for public and employee safety. Falling poles can create a public safety hazard. Furthermore, poles in poor asset health can present safety hazards for line workers who may need to climb the pole during restoration work, particularly if the pole gives way under the line worker's weight.

Q. Are any pole replacements based on age alone?

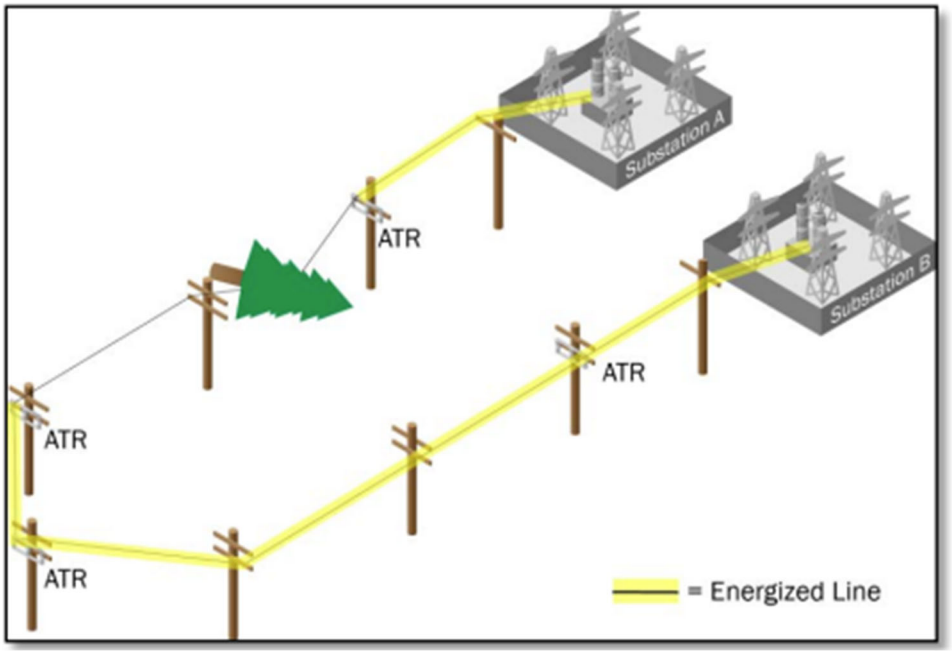
A. No. This was contemplated in the 2023 version of the Reliability Roadmap, but Liberty's audit concluded that replacing all LVD poles greater than a certain age was not warranted. The Company concurs with this finding of the audit, and the Company has correspondingly reduced its projections of how many LVD poles will need to be replaced in future years from what was shown in the 2023 Reliability Roadmap.

ATR Loops

Q. What are Automatic Transfer Recloser ("ATR") Loops?

A. As discussed in the Reliability Roadmap, an ATR Loop is a set of reclosers installed between adjacent circuits that work simultaneously to automatically restore power to many impacted customers when power loss is detected. Figure 34 below shows how ATRs maintain power for a large part of the system following an incident that would have caused more interruptions to customers.

FIGURE 34
ILLUSTRATION OF ATR LOOP



Reclosers are single-phase or three-phase interrupting devices installed on electric distribution lines for circuit sectionalizing. Reclosers typically have a predetermined sequence of operation, tripping several times before locking out in the open position. An ATR Loop recloser control includes additional programming beyond a standard recloser. This programming automatically opens and closes the strategically placed reclosers to

enable impacted customers to be fed from the adjacent source within the loop. This automated, fast response is the key factor driving customer reliability benefits.

ATR Loops have historically been installed as part of Grid Automation/ Modernization, but the Company moved this work into the LVD Lines Reliability subprogram in Case No. U-21585 because it is well-established practice, and is incorporated into the Company's standard suite of reliability solutions. ATR Loops also provide a resiliency benefit by allowing the system to better withstand major weather events, but since they also provide a benefit to blue-sky reliability, they are included in LVD Lines Reliability rather than in the Resiliency subprogram discussed later in my direct testimony.

Q. What historical benefits have ATR Loops provided customers?

A. The Company's first ATR Loop was installed in 2010 and, as of December 2025, there were 199 ATR Loops in service providing over 216,000 customers with a self-healing smart grid that prevents or minimizes the impacts of outages. Figure 35 shows the previous five years of tabulated actual benefits.

FIGURE 35
ATR LOOP HISTORICAL RELIABILITY BENEFITS

Year	Customer-Outages Prevented	Customer-Outage-Minutes Avoided
2020	33,172	9,131,000
2021	36,098	23,375,000
2022	63,359	18,222,000
2023	69,339	18,059,000
2024	79,889	22,919,094
2025	49,540	24,267,346
Total	**365,730**	**126,307,440**

Circuit Exit Enhancements and ROW Projects

Q. What work does the Company include in circuit exit enhancements?

A. The Company installs circuit exit switches on each phase outside the substation fence, providing additional safety by creating an isolation point for line workers in case the substation (and substation equipment) becomes energized. If the substation becomes energized without having the circuit exit switches opened, the line workers could be at serious risk of contact with an energized line while working on that line. In the instant case, the Company is proposing a moderate increase in circuit exit projects in order to complete this work on all feasible substations on the Company's system, after which this investment category could be wound down.

Q. What work is included in ROW projects?

A. This investment category is used to procure necessary land or land rights for LVD projects, including both lines and substations. Acquiring the necessary land rights is essential to enabling LVD line projects across multiple capital subprograms. These projects are critical to prepare for LVD construction and adequately support the project that is depending on the new rights. New rights are required for new LVD lines, LVD line relocations or off-center rebuilds, and improved easements where rights are determined to be inadequate. ROW spending is generally correlated with overall levels of investment in other investment categories in this sub-program, particularly with targeted circuit improvement categories. The Company's projected increased investment in those other investment categories is driving increased test year projections for ROW procurement in the instant case, although the increase in ROW spending is proportionally less than that in other investment categories in this sub-program. Recent ROW spending is shown in Figure 36 below.

FIGURE 36
HISTORICAL ROW SPENDING – LVD LINES RELIABILITY

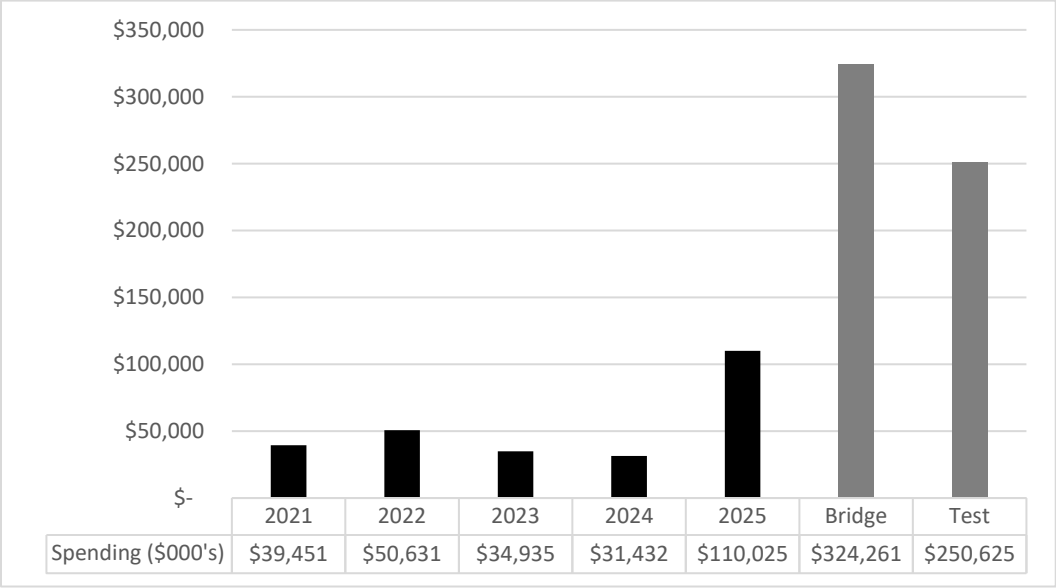
	2021	2022	2023	2024	2025
Spending	$3,937,398	$4,601,269	$5,049,816	$6,184,429	$7,587,281

LVD Lines Reliability: Overall Investment and Benefits

Q. What is the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Reliability subprogram?

A. The Company is projecting LVD Lines Reliability capital expenditures of $324,261,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 16, column (k), and $250,625,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 16, column (l). The Company's historical actual spending in the LVD Lines Reliability subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 16, and below in Figure 37.

FIGURE 37
LVD LINES RELIABILITY SUBPROGRAM EXPENDITURES



Q. How will the projected LVD Lines Reliability expenditures support the Reliability Roadmap?

A. The increased LVD Lines Reliability expenditures outlined in this case are critical for the plan that is defined in the Reliability Roadmap. The increases in investment in this subprogram are mostly driven by increased investments in zonal health improvements and pole replacements relative to pre-Reliability Roadmap levels. As the Reliability Roadmap makes clear, investment is needed in improving LVD zonal health and replacing LVD poles to deliver improve reliability for customers, while managing the challenges of increasingly severe weather. The projected benefits provided by investments in the Company's targeted zonal improvements, which substantially reduce outages, and in ATR Loops, which can completely mitigate customer outages, are necessary to achieve the Company's glidepath for reducing SAIDI.

Increased investment in this subprogram, relative to pre-Reliability Roadmap levels, is also driven by investments in voltage conversions and open-wire secondary conversions to multiplex which will deliver safety and capacity benefits to customers, particularly in vulnerable communities.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 38 below.

FIGURE 38
LVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Projects	Bridge Period # of Units	Test Year Capital	Test Year # of Projects	Test Year # of Units
Targeted Circuit Improvement *strategies:*						
• Zonal Health Improvements	$46,000,000	152	97 Miles	$34,890,000	91	72 Miles
• Secondary	$19,922,000	24	71 Miles	$14,664,000	19	58 Miles
• Voltage Conversions	$39,534,000	34	161 Miles	$34,106,000	38	239 Miles
• Underground Cable Rejuvenation	$24,380,000	3 areas	26 Miles	$9,735,000	2 areas	18 Miles
ATR Loops	$26,029,000	56	56 Loops	$17,668,000	30	30 Loops
Pole Replacements	$150,973,000	~740	15,115 poles	$125,000,000	TBD	12,500 poles
Circuit Exit Projects	$4,090,000	85	N/A	$3,189,000	102	N/A
Right-of-way	$13,333,000	N/A	N/A	$11,373,000	N/A	N/A
Total	**$324,261,000**			**$250,625,000**		

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Reliability subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-167 (JMP-1), pages 2 through 16, and for the test year, listed in Exhibit A-168 (JMP-2), pages 2 through 7. The Company determined the projected costs of the projects in these exhibits based on the specific work scope for each project and historical costs of materials and labor from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Can you provide further explanation regarding the "units" columns in Figure 38 above?

A. This sub-program involves multiple types of projects, and it is difficult to summarize them with a single kind of unit in this figure. The columns labeled with numbers of projects in Figure 38 simply lists the total number of line items for zonal health improvements in Exhibits A-167 (JMP-1) and A-168 (JMP-2). For ATR Loops and Circuit Exit Projects, each exhibit line item is simply "1 project." For other categories, each exhibit line item has some number of miles or poles, and the columns labeled with numbers of units in Figure 38 reflect those totals. Note that Exhibits A-167 (JMP-1) and A-168 (JMP-2) include some zonal health improvement projects with "0.0 miles." In these instances, the Company is replacing equipment on the line but is not actually rebuilding mileage.

As mentioned earlier in my direct testimony, the Reliability Roadmap includes a plan to target approximately 85 zones per year, at an approximate annual cost of $35 million. In the bridge period, the Company's zonal health improvement projects address a total of 113 zones, while test year projects address a total of 91 zones.

Q. What are the different types of pole replacement projects listed in Exhibits A-167 (JMP-1) and A-168 (JMP-2)?

A. As discussed above, the Company began identifying pole replacements through its new groundline inspection program in 2025. In Exhibit A-167 (JMP-1), pages 2 through 11, the Company has listed a number of individual pole replacement projects for 2026 based on groundline inspections that have already been completed. Additionally, Exhibit A-167 (JMP-1), page 2, line 2, indicates that the Company projects to replace an additional 3,228

poles in the first four months of 2027 in response to further groundline inspections during 2026.

Exhibit A-168 (JMP-2), page 6, line 25, indicates that the Company projects to replace 12,500 poles in the test year in response to continuing groundline inspections.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Reliability subprogram?

A. LVD Lines Reliability projects form a critical part of the Company's glidepath for improving SAIDI as part of the Reliability Roadmap. In addition to driving system wide SAIDI improvements, LVD Lines Reliability projects consistently provide immediate benefits on the circuits or zones in which they are completed. The benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-167 (JMP-1), pages 2 through 16, and A-168 (JMP-2), pages 2 through 7. Types of benefits identified on the exhibits, and summarized in Figure 39, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete;
- Customers impacted – defines the number of customers benefiting from a project that improves voltage to ensure it remains within specifications for normal conditions; and
- Increase Safety by Installing Isolation Point at Sub – these isolation points installed just outside of the substation provide LVD line workers a visual open that they can operate to safely work on the circuit.

FIGURE 39
LVD LINES RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	29,463,122	27,879,140
Customers impacted	12,285	8,242
Increase Safety by Installing Isolation Point at Sub	85	102

Q. What are the historical unit costs for each of the LVD Lines Reliability investment categories?

A. Historical unit costs for three investment categories are provided in Figure 40. There are no unit costs for the ROW investment category because units are not identified for this work.

FIGURE 40
LVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2021	2022	2023	2024	2025
Targeted circuit improvements	$112,093 /project	$3,986 /project	$3,498 /project	$35,315 /project	$80,702/project
Pole replacements	$10,047 /pole	$14,738 /pole	$13,831 /pole	$5,758 /pole	$11,896 /pole
Circuit exit enhancements	$43,658 /project	$51,993 /project	$46,842 /project	$31,147 /project	$54,985/project
ATR Loops	$668,319 /loop	$440,805 /loop	$462,945 /loop	$423,990 /loop	$490,694/loop

Q. Can you further break down unit costs for targeted circuit improvements to reflect the four strategies that make up that investment category?

A. These costs are summarized in Figure 41 below. For 2021 through 2024, the Company's historical data only allows the Company to provide unit costs on a per-project basis, without accounting for the varying mileage of projects, with the exception of underground cable rejuvenation. The Company has per-mileage costs available for all strategies for 2025.

FIGURE 41
TARGETED CIRCUIT IMPROVEMENT STRATEGY UNIT COSTS

Strategy	2021	2022	2023	2024	2025
Zonal Health Improvements	$106,403 /project	$3,223 /project	$2,943 /project	$66,512 /project	$214,668 /project $486,727 /mile
Open-Wire Secondary Conversions	$54,276 /project	$218,630 /project	$96,645 /project	$78,297 /project	$163,841 /project $374,234 /mile
Voltage Conversion	$483,120 /project	$224,650 /project	$30,100 /project	$136,044 /project	$121,629 /project $154,450 /mile
Underground Cable Rejuvenation	$626,217 /mile	$357,738 /mile	$496,169 /mile	$1,004,504 /mile	$2,392,269 /mile

Q. Please explain any variation in unit costs over time.

A. Pole replacement unit costs increased after 2021 because the Company increased the standard for pole class size for added reliability, added resiliency, and to align with industry best practices. The increase in pole class size impacts the cost of the pole ranging from $50 to $250 depending on class and height.

In 2024, the Company's Supply Chain organization renegotiated contracts with pole vendors, which allowed for a decrease in pole unit costs in 2024. The increase in 2025 was due to the increased height of poles being used in the 2025 workplan, with an increase in projects requiring tree wire or aerial spacer cable that require taller poles for construction. These taller poles are more expensive than the shorter poles used in the past. Between 2024 and 2025, the Company's use of 60-foot class 2 poles increased by 205%, use of 60-foot class 3 poles increased by 487%, and use of 65-foot class 2 poles increased by 279%. The difference in cost between a 50-foot class 3 pole and a 60-foot class 2 pole is $409.

Individual projects for zonal health improvements can vary widely in cost, based on specific project conditions and size of the projects, and as a result, the per-unit average cost can also vary. The lateral fuse addition projects completed in 2022 and 2023 each had a significantly lower cost than prior years' targeted circuit improvement projects. Accordingly, the unit costs for 2022 and 2023 for this investment category were less than prior and subsequent years.

Unit costs for underground cable rejuvenation increased in 2024, and especially in 2025, due to the challenges with this work, as previously discussed. As noted above, this is one reason the Company is scaling back its increase from what was proposed in the Reliability Roadmap, and the bridge period and test year projected unit costs are lower than the levels seen in 2024 and 2025.

It is important to note that, prior to the Reliability Roadmap, voltage conversions and open-wire secondary conversions were only performed tactically as needed, so any historical unit costs for that work may not be comparable to at-scale work that began in earnest in 2025.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance in work required ranging from $2,000 to as high as $3,000,000 or more per project. The Company builds a project plan for each year for this subprogram to achieve the reliability improvements needed for the LVD system and bases its investment levels on the cost of those projects.

LVD Repetitive Outages

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Repetitive Outages subprogram.

A. The LVD Repetitive Outages subprogram is similar to the LVD Lines Reliability subprogram in the types of work performed and how projects are identified. However, the LVD Repetitive Outages subprogram is designed to specifically address areas of the distribution system that consistently experience recurring customer interruptions, measured by the CEMI index, inclusive of MEDs. CEMI measures how many customers have experienced more than a given number of interruptions in a particular year. The LVD Repetitive Outages subprogram focuses on targeted corrections within discrete areas that have demonstrated patterns of frequent interruptions. Projects under this program can often be scoped, designed, and constructed more efficiently than broader, system-wide reliability projects. This allows the Company to respond more quickly to emerging CEMI concerns while still applying established engineering standards, cost controls, and prioritization processes. As a result, the subprogram enhances the Company's ability to address repetitive outage conditions in a timely manner and improve service quality for affected customers.

Q. How is this sub-program related to the Commission's standards on CEMI?

A. The LVD Repetitive Outages subprogram is affected by the current version of the Commission's Service Quality and Reliability Standards from Case No. U-20629 that went into effect on April 10, 2023. Those standards specify that utility performance is unacceptable if more than 6% of customers have four or more outages in a calendar year (CEMI-4+), and they also establish new bill credit rules for customers with too-frequent outages. In 2024, 10.9% of the Company's customers experienced four or more outages,

increasing to 11.7% in 2025. Approximately 4% of the 2025 customers in this category were directly affected by two catastrophic storm events in March and May. These results underscore the importance of the Zonal Health and Repetitive Outage programs in hardening the entire LVD system and reducing the number of customers impacted during severe weather. When considering these results, the Company has identified a need to increase investment in the LVD Repetitive Outages subprogram to reduce CEMI-4+ and address locations experiencing frequent customer interruptions.

The LVD Repetitive Outages subprogram represents one component of the Company's broader strategy to address CEMI-4+ performance. This subprogram enables targeted and timely actions to mitigate repeat outages for customers experiencing frequent interruptions within a given year. However, achieving sustained reductions in overall CEMI-4+ levels and progressing toward the 6% performance standard will also depend on the execution of larger, system-wide reliability projects that address underlying infrastructure conditions and exposure to major outage drivers. Together, these programs work in a complementary manner to reduce both near-term repetitive outages and longer-term reliability risk.

Q. How does the Company plan to address this concern?

A. The Company is increasing investment in the Repetitive Outages sub-program from recent levels to ensure it achieves the Service Quality and Reliability Standard of 6% in the future. In 2025, the Company invested more in Repetitive Outages than in any other recent historical year, and it plans to increase even further from there. The Company is projecting an approximately 2% reduction each year until it reaches 6% in 2028 based upon current investment levels. The Company needs to invest at the levels outlined in the instant case

to achieve the Commission's standard beyond 2026, which is reflected in the Company's projected bridge period and test year investment levels in the instant case. Each percentage point of CEMI above the Commission's standard requires the Company to invest in addressing 161 zones, at a cost of approximately $14.45 million.

Q. What kinds of improvements are made for targeted zones in the Repetitive Outages sub-program?

A. Different solutions are considered depending on the specific conditions of the area being targeted. Depending on specific circuit conditions and attributes, typical investments include:

- System protection upgrades (e.g., fuses, switches, reclosers), using devices that maintain continuity of service by segmenting the electric distribution system into smaller sections, minimizing the number of customers affected by any individual outage;
- Replacing deteriorated or non-standard equipment such as poles, cross-arms, conductor, pins and insulators, lightning arrestors, non-standard equipment, and cutouts;
- Relocating portions of lines from dense tree or other poor access conditions for reduced tree interruptions, improved restoration time, and safer more accessible work locations for crew safety;
- Upgrading conductors that are at risk of contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection, because both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and therefore associated interruptions; and
- Relocating portions of overhead lines underground to reduce tree-related and severe weather interruptions.

Q. How does work in the LVD Repetitive Outages subprogram connect to the plans outlined in the Reliability Roadmap?

A. Work in the LVD Repetitive Outages subprogram is similar in nature to that in the LVD Lines Reliability subprogram, so the discussion is closely related to the Zonal Health

Improvements component of the Reliability Roadmap. As established in the Reliability Roadmap, the Company is planning an increase in its LVD Zonal Health Investment Plan to make these circuit health improvements. While this increase primarily affects the LVD Lines Reliability subprogram, work in the LVD Repetitive Outages subprogram also supports the goal of addressing zones in poor health, in addition to its primary goal of addressing customers with high CEMI.

Q. Do the investments included in the Repetitive Outages subprogram also help support SAIFI improvements, as described in the Reliability Roadmap?

A. Yes. There is a correlation between SAIFI, including MEDs, and the MPSC's CEMI performance standard, which does include storms. Company witness Duke provides a forecast of SAIFI, including MEDs, and CEMI. To improve customer satisfaction, the Company continues to focus on sustained SAIFI performance to assist in meeting the Repetitive Outages performance standard. An improving SAIFI metric increases the probability that the CEMI-4+ metric will be met. By targeting investment to the worst performing areas of the distribution system, the Company expects to improve SAIDI, SAIFI, and CEMI. This reduces outage length and the frequency of outages experienced by customers.

The proactive investments made to replace deteriorated assets and reduce customer exposure to outages improves employee and public safety. Furthermore, investments in the LVD Repetitive Outages subprogram reduce overall costs associated with emergent response for additional interruptions in the capital subprogram LVD Lines Demand Failures. The benefits for bridge period projects are identified in the Benefit Type and Benefit columns of Exhibit A-167 (JMP-1), pages 17 through 20 and Exhibit A-168

(JMP-2), pages 8 through 10 are consolidated into Figure 42 below. Types of benefits identified on the exhibit and shown below include customer-outage-minutes avoided. As defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete.

FIGURE 42
REPETITIVE OUTAGE BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	24,128,754	21,711,793

Q. How does the Company identify LVD Repetitive Outages projects?

A. RAE data, as discussed previously in the LVD Lines Reliability section of my direct testimony, is the primary input in deciding where to invest for repetitive outages. One RAE output is a monthly zonal analysis report, which is reviewed by each area's LVD circuit planner. The report is broken down to identify specific zones, showing the number of customers that experience repetitive outages in each zone of the circuit. By focusing on areas where customers are likely to experience four or more interruptions annually, the Company can develop projects that have the greatest reliability benefit for the highest number of customers first. To do this, the Company identifies zones with a high consistency ranking—a part of the zonal score illustrated in Figure 21—and a total reliability ranking below the threshold that would otherwise initiate a targeted circuit improvement project in the LVD Lines Reliability subprogram. These zones are likely to continue to experience interruptions, tend to have a smaller number of customers affected, are typically farther away from the circuit source, and thus contribute significantly to CEMI. Addressing these zones with Repetitive Outage projects may not produce the same

total customer minute savings as targeted circuit improvement projects but will meaningfully improve CEMI.

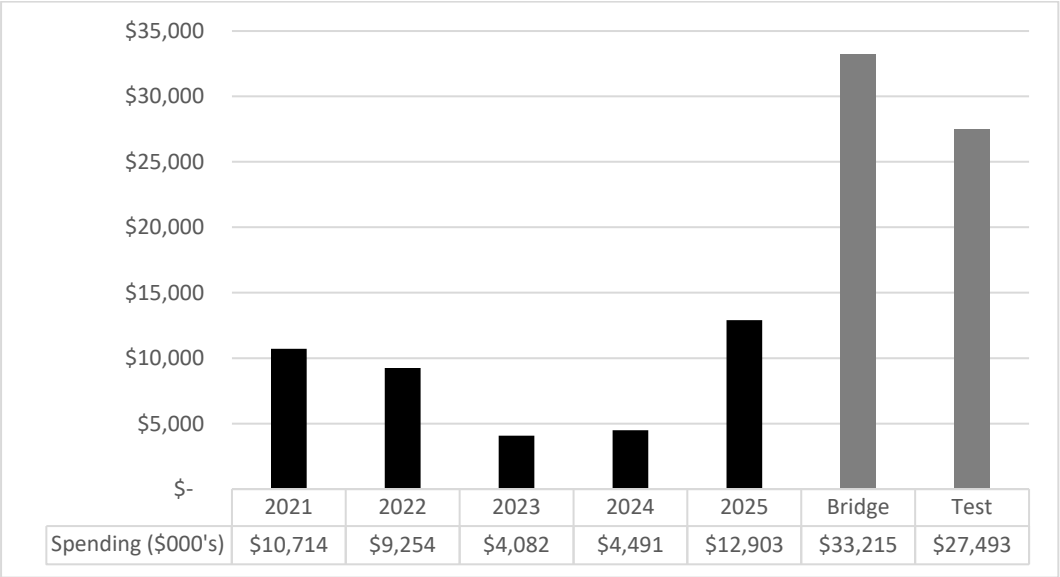
The Company also uses feedback from field operations to identify areas that may also be creating outage concerns. This is then compared to the RAE and zonal report data to pinpoint the causes as described previously.

In addition to using RAE data, the Company focuses on customers experiencing CEMI-4+ and prioritizes them for projects in this subprogram, even if they might not have otherwise been considered for investment prioritization in the LVD Lines Reliability subprogram.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Repetitive Outages subprogram?

A. The Company is projecting LVD Repetitive Outages capital expenditures of $33,215,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 22, column (k), and $27,493,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 22, column (l). The Company is planning to complete 236 projects in the bridge period and 172 projects in the test year. The Company's historical actual spending in the LVD Repetitive Outages subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 22, and below in Figure 43.

FIGURE 43
LVD REPETITIVE OUTAGES SUBPROGRAM EXPENDITURES



Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Repetitive Outages subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-167 (JMP-1), pages 17 through 20 and Exhibit A-168 (JMP-2), pages 8 through 10. The Company developed the projected costs of the projects in the exhibits considering typical costs for materials and labor, and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects. While projects have been identified and listed for this subprogram, the Company will continue to evaluate areas on the system, developing solutions for those areas following the process described below, and potentially reprioritizing work based on these evaluations.

Unit costs are higher in the bridge period and test year in this case than historical averages. The Company recognizes that CEMI performance is not improving significantly, even as it addresses anomalies identified in inspections and completes lateral fusing within other subprograms. Therefore, the Company is shifting investments within this

subprogram to focus on more robust, and more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire.

Q. Please explain the year-over-year variation in spending in this subprogram.

A. Overall investment in this subprogram was lower in 2023 than in earlier years as the Company focused on addressing anomalies identified during inspections, targeted zone projects, and overhead to underground relocation projects. Shifting investment from Repetitive Outages to LVD Lines Reliability and LVD Resiliency accomplishes the same goal of reducing SAIDI and CEMI. Investment levels increased modestly from 2023 to 2024, and then increased in 2025. In the bridge period and test year, the Company plans to continue to increase this investment level. The purpose of this increasing investment is to reduce the number of repeat outages a customer experiences once poor performance is identified, even if the SAIDI benefit would not prioritize the project in LVD Lines Reliability.

Q. In its U-21870 Order, the Commission emphasized the need for a "robust presentation [in LVD Repetitive Outages] in the [C]ompany's next rate case clearly demonstrating that the amounts approved were actually spent on improving the problem of repetitive outages". What are you presenting in response to this direction?

A. Please refer to Exhibit A-170 (JMP-4). This exhibit is similar to an exhibit provided in Case No. U-21870, per the Commission's final Order in Case No. U-21585, and Exhibit A-170 (JMP-4) provides further information as well. Pages 1 through 3 of Exhibit A-170 (JMP-4) identify all of the projects in the LVD Repetitive Outages sub-program that had

substantive investment in 2025, and shows how many outages occurred both before and after work was completed.[3]

Beyond this, pages 4 through 8 of Exhibit A-170 (JMP-4) show the projected bridge period projects for the instant case, along with the total outages experienced in 2024 and 2025. Pages 9 through 12 of Exhibit A-170 (JMP-4) show the same information for test year projects. The data in Exhibit A-170 (JMP-4) demonstrates that planned LVD Repetitive Outage projects are targeting sections of the system that have been experiencing outage issues, and that historical projects have been successful in dramatically reducing outages. As shown in Exhibit A-170 (JMP-4), page 3, line 33, the 2025 project zones had experienced a total of 191 outages between 12 and 24 months prior to construction, and a total of 193 outages in the 12 months prior to construction. Since construction, the same zones have experienced a total of just 26 outages.

Q. In its U-21870 Order, the Commission also indicated the need for the Company to provide "evidence showing the correlation (as suggested by the Attorney General) between avoided customer minutes and actual minute reductions from historical outage minutes experienced by customers on that circuit." How do you respond?

A. My understanding of the Attorney General's position in Case No. U-21870, which the Commission adopted in its order, is that the projected avoided customer outage minutes that the Company provides for Repetitive Outages should reflect a reduction from historical outage minutes experienced by customers on that circuit. However, the Company is not able to show that correlation because it is contrary to the way in which the Company projects avoided customer outage minutes. The Company's projections of avoided

[3] Similar information for projects completed in 2023 and 2024 was provided in Exhibit A-169 (JMP-4) in Case No. U-21870.

customer outage minutes, as shown for Repetitive Outages at Exhibit A-167 (JMP-1), pages 17 through 20 and Exhibit A-168 (JMP-2), pages 8 through 10, are not attempting to reflect a reduction to previous customer outage minutes experienced at the same location. Rather, as discussed in Company witness Duke's direct testimony, avoided customer outage minutes is a way to model the future outages that would likely occur on a circuit, line, or substation if a project is not done and the asset were to fail. For example, Ms. Duke states that if a transformer is at risk of failure, and the failure would cause 10,000 customers to lose power for 24 hours, the Company will conclude that replacing the transformer avoids those outages in the future even if there had not been actual historical outages to consider. While the Company is targeting areas where repeated outages have occurred in the Repetitive Outage program, the Company's projected avoided customer outage minutes is still a projection based on the likely outages avoided in the future if the work is not performed, but is not a calculated reduction to previous customer outage minutes.

Q. What benefits will customers see from continued investment in the LVD Repetitive Outages subprogram?

A. Continued investment in the LVD Repetitive Outage subprogram, at the projected levels, is necessary for the Company to address customers with high CEMI and for the Company to meet the Commission's CEMI-4+ standard.

LVD Lines Rehabilitation

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Lines Rehabilitation subprogram.

A. The LVD Lines Rehabilitation subprogram includes capital repair or replacement of LVD lines equipment that has not actually failed but has been assessed to be at risk of failure in the near term. This subprogram consists of five investment categories:

(i) imminent rehabilitation;

(ii) meter voltage anomalies;

(iii) subsurface transformer replacements;

(iv) modem replacements; and

(v) vintage underground replacements.

Q. Are any of these investment categories new in recent years?

A. Yes. Subsurface transformer replacements was a new investment category in Case No. U-21585. It represents work that was newly prioritized during the asset health analysis that informed the 2023 Reliability Roadmap. Additionally, the meter voltage anomalies investment category was newly defined in Case No. U-21870, based on voltage anomalies that the Company has recently begun to identify using AMI. This effort was driven in part from the Commission's final Order in Case No. U-21389, directing the Company to continue identifying use cases for value-focused AMI metrics. In the instant case, the investment category for vintage underground replacements is newly defined.

Q. Has this subprogram historically included any other investment categories?

A. Yes. Prior to 2024, this subprogram included an investment category called LVD asset assessment repairs (formerly called Security Assessments; please refer back to the section

of my testimony on Demand Failures). As the Company initially explained in Case No. U-21389, that work is now completed within the LVD Lines Demand Failures subprogram based on just P1 and P2 anomalies that are identified in inspections. If Priority 3 ("P3") or Priority 4 ("P4") anomalies are identified, they may be prioritized for action in the imminent rehabilitation investment category in this subprogram. Figure 44 presents the types of hazards classified as P3 and P4. The hazards are listed by the priority code for the anomaly.

FIGURE 44
LVD ASSET ASSESSMENT HAZARD CODES

Code	Description
P3 - Failure Expected Before Next Inspection	
P3A	Broken Guy - Leaning Pole
P3B	Pole: Damaged
P4 - Heightened Risk of Failure	
P4A	Broken/Missing Cross-arm Braces
P4B	Broken Guy - Non-Leaning Pole
P4C	Damaged Equipment (Transformers, Reclosers, Etc.)
P4D	Lightning/Flashover Burn Marks
P4E	Poorly Sagged Line

Q. Please explain the imminent rehabilitation investment category.

A. The imminent rehabilitation category addresses issues that arise in which an actual failure has not occurred, but repair or replacement is required to prevent outages and the additional expenses associated with fixing following failure as opposed to doing planned, straight-time work with lower unit costs and higher efficiency. Imminent rehabilitation projects deal with conditions identified outside the Company's inspection cycles and normal planning work, but there is a reduced urgency for repair compared to LVD Lines Demand Failures projects. Imminent rehabilitation projects include:

- P3 and P4 conditions, as identified in Figure 40, may be addressed in this investment category, such as replacing poles with visible damage or

deterioration identified outside of the inspection cycle by line crews or customers.

- Underground cable repair after a fault is isolated and customers are restored under service restoration activities. If this is the first time the section of line has faulted, the Company typically will expose the fault and splice it. If this section or area has experienced multiple faults or the vintage of the cable warrants replacement, the Company will develop a project to replace the faulted section of cable and, in some cases, adjacent sections of cable as well.

- Underground padmount equipment may require relocation or replacement due to ground shifting that causes leaning or sinking.

- Underground padmount equipment inspection replacement. Each year padmounted equipment is visually inspected around the exterior for any signs of oil leaking or holes that expose electrical components. When found, the equipment is replaced.

- Primary or secondary voltage improvements identified through customer complaints, power flow analyses, or line crew reports and include projects such as transformer replacement, conductor upgrades, load balancing, or voltage conditioning device installation such as capacitor banks or voltage regulators.

- Deteriorated conductor or equipment replacement, including replacement of secondary conductors that are losing the protective coating, severely rusting equipment, or any wear and tear on the conductor that requires replacement.

- Radio frequency interference projects requiring pole top component or other equipment replacements to resolve interference to communications, radios, and other devices as required by Federal Communications Commission rules.

- Clearance violations of conductor or equipment with respect to structures or the ground that are not an immediate risk requiring relocation, pole upgrades, or new pole installations.

Q. Please describe the general inputs that the Company uses to identify issues that must be addressed by the imminent rehabilitation investment category.

A. The Company collects data through its electric operations organization. For example, there may be locations that electric operations employees have frequently visited to restore service for a failed underground cable in the same subdivision. This team conveys this information to LVD circuit planners so they can investigate and create a project for a full

replacement of the underground cable, and possibly live-front transformers or padmounted switching equipment in that subdivision, if necessary.

Q. Please explain the meter voltage anomalies investment category.

A. Rule 702 of the Commission's Standards of Quality of Services requires that the Company provide customers with voltage that is ±5% of nominal voltage. The Company is able to use its AMI for continuous monitoring of voltage at the service delivery point to customers, and from this the Company knows that over 99% of customers receive voltage at compliant levels. However, voltage anomalies do occur. When voltage is unacceptably low, this is typically due to heavily loaded secondary and line transformers. When voltage is moderately high (between 5% and 10% greater than nominal), this is typically due to voltage regulation device issues. When voltage is greater than 10% above nominal, this is typically due to internally-faulted line transformers that are still energized. The large majority of voltage anomalies fall in the second of these categories. Historically, the Company has fixed voltage anomalies as they are reported by customers on a reactive basis, although in some cases a customer may not be aware if their voltage is too high or too low. Going forward, though, the Company plans to use its AMI data to proactively address voltage compliance concerns, and is therefore proposing to invest in correcting all three voltage anomaly causes, and will replace line transformers, mitigate regulator issues, and mitigate low voltage secondary issues. This is also discussed in the Reliability Roadmap.

Q. Please explain the subsurface transformer replacement investment category.

A. As discussed in the Reliability Roadmap, the Company's underground system still has some original subsurface transformers installed; at the time of this filing, there are still 57 of these transformers. These transformers do not have a major impact on reliability but do

pose a safety risk for Company employees and the public. Since they are underground, employees have difficulty accessing and repairing them when they fail, and their location makes it difficult for members of the public to recognize them and take care to avoid them. When subsurface transformers do fail, outages last approximately four times as long as during padmount transformer failures, given the difficulty of repair, and subsurface transformers are also prone to leaking subterranean oil. To address these risks, the Company plans to replace all subsurface transformers with padmount transformers by the end of 2026.

Q. Please explain the modem replacement program investment category.

A. The Company has begun a project to replace cellular modems that are installed inside control devices (e.g., Capacitors and Line Voltage Regulators) throughout the LVD grid. The present vendor of the Company's cellular modems announced a cessation of manufacturing in 2020 and informed the Company that it will end support in 2029. An end of support announcement means that security patches, firmware updates, and hardware support/repair will no longer be available, which negatively impacts equipment reliability and security. The security patches protect the Company from external parties accessing the data and other cyber threats. Also, the equipment hardware will no longer be available, reducing or eliminating the capabilities enabled by automation and conservation voltage reduction ("CVR"). Due to the large quantity, geographic locations, and physical effort needed to replace each modem, it is imperative to begin replacement efforts prior to the end of support date. Over the course of the following years, the Company will replace the total population of 5,000 cellular modems, completing approximately 800 replacements per year. The program has replaced 1,153 modems for capacitors through year end 2025.

An additional 800 capacitor modems have been selected to be replaced in 2026. Existing capacitor infrastructure may contain defects, locations with failed modems exist, and the electric field lab requires support from line workers as a limited quantity of locations may require hardware replacements along with a modem installation. This process increases the time and resources needed to update modems on a large scale over a varied geographical area.

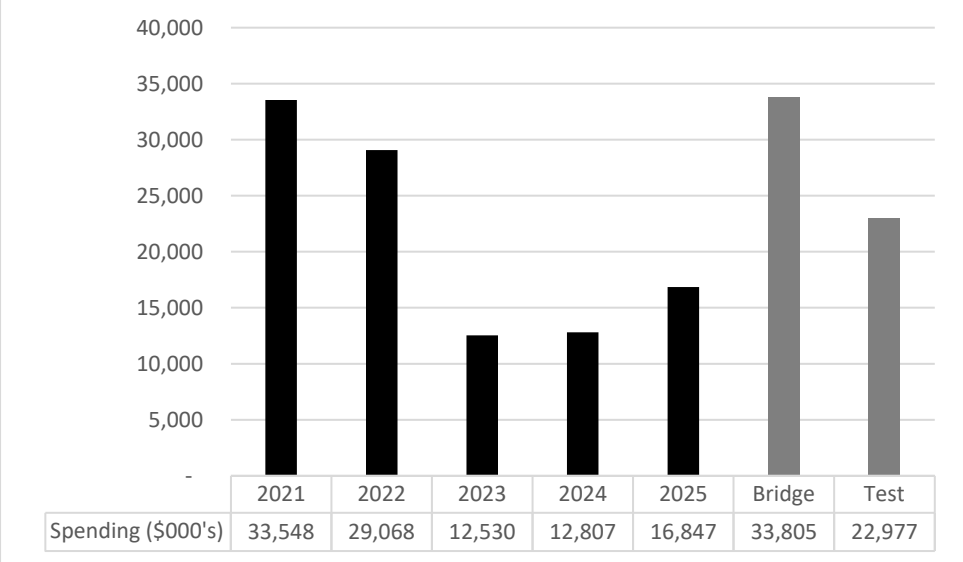
Q. Please explain the vintage underground replacement investment category.

A. The Company has specific areas of its system where vintage underground conductor presents restoration challenges due to inherited Y-splices, live-front equipment, and inaccessible underground cable. This is particularly common in mobile home parks and older subdivisions. In some mobile home parks, larger homes have been built over the Company's underground facilities, and when the infrastructure was originally installed Y-splices were used as well as live-front equipment. When a fault occurs, crews need to de-energize a significant portion of the area to locate the fault and make repairs, resulting in long-duration outages for affected customers, many of whom are economically vulnerable. Completing this work proactively as planned construction in this sub-program – rather than during an outage – will allow the Company to schedule around weather conditions and provide customers with adequate notice to prepare for any necessary outages during equipment replacement. An example of the concept and scope of work, related to the project proposed in the instant case, is included as Exhibit A-171 (JMP-5). The Company plans to address this issue at one mobile home park through the project that is planned for the test year of the instant case.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Rehabilitation subprogram?

A. The Company is projecting LVD Lines Rehabilitation capital expenditures of $33,805,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 26, column (k), and $22,977,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 26, column (l). The Company's historical actual spending in the LVD Lines Rehabilitation subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 26, and below in Figure 45.

FIGURE 45
LVD LINES REHABILITATION SUBPROGRAM EXPENDITURES



	2021	2022	2023	2024	2025	Bridge	Test
Spending ($000's)	33,548	29,068	12,530	12,807	16,847	33,805	22,977

Q. How did the Company develop its projected expenditures in this subprogram?

A. While the Company now addresses LVD asset assessments in the LVD Lines Demand Failures sub-program (which led to lower investment levels in this sub-program in 2023 and 2024), the levels of investment for the bridge period and test year will continue to address system deterioration and the resulting anomalies identified on the system recently or in-year. The bridge period and test year also include the newer investment categories

for modem replacements, subsurface transformer replacements, and meter voltage anomalies. The new investment category for the instant rate case is vintage underground replacement, expected to start during the test year. The bridge period and test year spending amounts will enable the investment needed to complete the projects identified.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and the test year for each investment category as identified in Figure 46.

FIGURE 46
LVD LINES REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Imminent rehabilitation	$13,475,000	320	$5,299,000	123
Subsurface transformers	$1,940,000	18	$0	0
Modem Replacement Program	$2,998,000	800	$2,988,000	800
Meter Voltage Anomalies	$15,392,000	N/A	$11,658,000	N/A
Vintage Underground Replacement	$0	N/A	$3,022,000	1
Total	**$33,805,000**		**$22,977,000**	

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Rehabilitation subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-167 (JMP-1), pages 21 through 26, and for the test year, listed in Exhibit A-168 (JMP-2), pages 11 through 13. The Company developed the projected costs of the projects in these exhibits

considering estimated costs for materials and labor and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects. Note that the Company only creates orders for specific modems close to the time that they are replaced, so there are no specific projects listed for this investment category. Spending amounts are based on a continuation of the same volume of work going forward. Additionally, the Company does not have specific projects identified for meter voltage anomalies. The Company will identify specific proactive projects for this investment category closer to the time of project execution based on up-to-date AMI data; the projected work volume for meter voltage anomalies is based on the historical levels of anomalies visible in the AMI data. Finally, it is important to note that the 18 subsurface transformer projects in the bridge period will complete the work in this category.

Q. What benefits will customers realize through the Company completing work in the LVD Lines Rehabilitation subprogram?

A. The LVD Lines Rehabilitation subprogram addresses conditions that could result in interruptions to customers or present unacceptable system operating conditions and, therefore, provides a benefit to customers by reducing the likelihood of future actual failures. By replacing or rehabilitating equipment before it fails, work can be completed in a more economical manner by having the correct materials and resources in place before work begins. The approximate number of customers benefitting from known bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-167 (JMP-1), pages 21 through 26, and A-168 (JMP-2), pages 11 through 13.

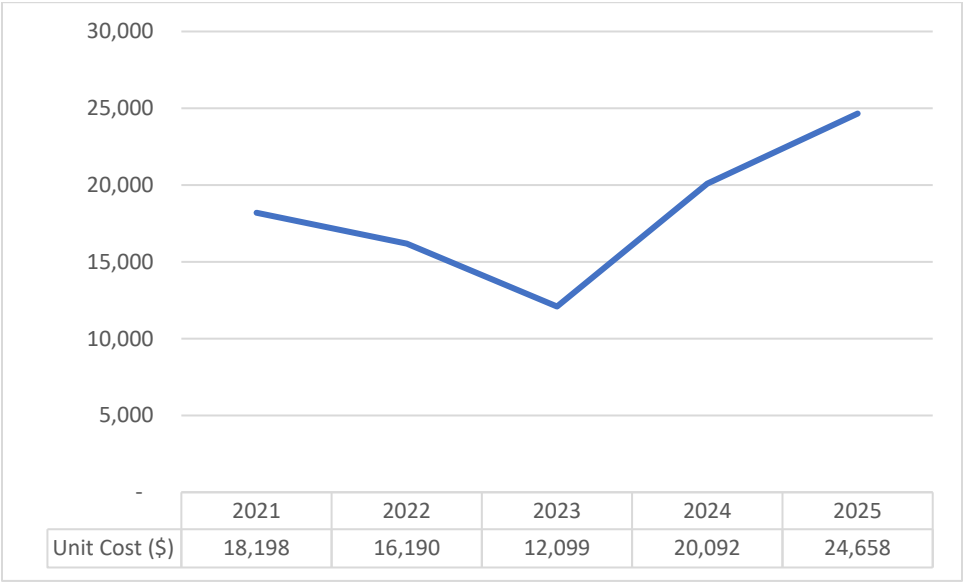
Q. Please explain why some of the imminent rehabilitation projects in the LVD Lines Rehabilitation subprogram have similar customer benefits.

A. The work required for many of these projects is similar in nature and therefore some projects are estimated to have similar benefits based on the reported finding and historical orders of the same type. To improve secondary voltage for customers, it typically requires new secondary conductor and a transformer with five customers receiving the benefit. When a pole is replaced for deterioration in this subprogram, on average it benefits 242 customers.

Q. What are the historical unit costs for the imminent rehabilitation projects in the LVD Lines Rehabilitation subprogram?

A. The historical unit costs are provided in Figure 47 below.

FIGURE 47
LVD LINES REHABILITATION INVESTMENT CATEGORY UNIT COSTS



	2021	2022	2023	2024	2025
Unit Cost ($)	18,198	16,190	12,099	20,092	24,658

Q. Please explain any variation in unit costs over time.

A. Imminent rehabilitation can vary due to variations in size and complexity of work orders. Since 2021, projects in the imminent rehabilitation investment category have generally

shifted to more complex projects. Prior to 2022, this investment category included single location deterioration repairs as part of what is now LVD asset assessments in the LVD Lines Demand Failures subprogram. As those LVD asset assessments have taken place, inspecting locations on a faster cycle and addressing these single-location items, the projects that are repaired in the imminent rehabilitation investment category are, instead, increasingly multi-location replacement efforts for reconductoring old conductor, larger underground replacement projects, and deteriorated equipment replacements. These multi-location projects are more expensive on a per-project basis.

Additionally, while installing new underground cable can be relatively straightforward when replacing existing underground infrastructure, the cost can rise significantly when it involves designing around other existing underground facilities that can cause deviations from the original path. This investment category has seen an increase in underground replacement-related orders, from 43% of the total in 2024 to 48% in 2025, and this has led to a corresponding increase in overall cost per project.

Q. Does an average unit cost accurately reflect the expected spend per project for this subprogram?

A. No. There is a wide variance among work required ranging from $1,000 to as high as $900,000 per project in the imminent rehabilitation investment category. While there is a reasonable volume of units, and an average unit cost could be used to analyze the projections for the overall subprogram, but not the cost of any individual project. Additionally, in the test period, the vintage underground replacement investment category consists of one project projected at $3,022,000.

Resiliency

Q. What is the purpose of the Resiliency subprogram?

A. As discussed in the Reliability Roadmap, the Company's distribution objectives include building a system that is both reliable and resilient. While much of the overall Reliability Program is focused on improving reliability, this Resiliency subprogram has a particular focus on enhancing resiliency. It does this by proactively investing in strategic distribution system hardening to increase the distribution system's ability to withstand major storm events and recover from those events more quickly. As noted earlier in my direct testimony when introducing the Reliability Program, the primary purpose of Resiliency subprogram investments is to limit customer interruptions following major weather events, as opposed to solely improving blue-sky SAIDI (i.e., reliability primarily experienced during normal conditions).

Q. How does the focus of the Resiliency subprogram investments compare with the Company's other investments in the Reliability Program?

A. The Company's other Reliability Program investments are primarily identified based on historical performance of portions of the system, with a focus on improving blue-sky reliability, measured in customer-outage-minutes. However, focusing only on normal weather reliability leaves parts of the system exposed to extreme weather events that result in long and costly outages and customer hardships.

Resiliency subprogram investments are meant to focus on prevention, recovery, and survivability, particularly during large weather events. Preventing outages is the ideal way to reduce the number of outages to customers. Each outage represents a unit of work that must be completed by line workers who at times must travel from states located significant

distances from Michigan. If this can be avoided through prevention, the amount of time spent on restoring service following a major event is considerably reduced. Likewise, survivability increases the system's ability to withstand a storm system without failure. Finally, recovery improvements address those times when prevention and survivability are not enough, and the outage occurs. Investing in recovery reduces the duration of outages that do occur.

Q. What is the purpose of a standalone Resiliency subprogram?

A. The Company has experienced an increasing frequency of high-speed wind gusts in its service territory over the past several years which, along with system deterioration, have resulted in an increase in the amount and severity of electrical outage incidents. For example, an August 2021 multi-day storm with 70 mile-per-hour wind gusts resulted in interruption to 401,000 of the Company's customers, with restoration lasting up to seven days. A subsequent storm in December 2021 had peak wind gusts of 79 miles per hour, interrupting more than 210,000 of the Company's customers, with restoration lasting up to four days. Furthermore, two ice storms in February 2023 interrupted approximately 400,000 customers, with restoration lasting up to eight days. Please see Company witness Jeffrey P. Dickey's testimony for more recent examples. These interruption events—which strain the distribution system beyond previously experienced levels—have increased the Company's focus on ways to mitigate major weather events. The Company's Reliability Roadmap takes projections of worsening climate into account and correspondingly calls for additional resiliency investments to harden the system and reduce customer outages even as the system faces more storms.

Q. How does the Resiliency subprogram align with the Reliability Roadmap?

A. The Reliability Roadmap is focused on both improving system reliability under normal operating conditions and improving resiliency under extreme conditions. In the Reliability Roadmap, the Company defines its strategy for LVD resiliency, based on a ramp-up of LVD overhead-to-underground conversions; continuing to invest in fractionalization; and continuing to install ATR loops. The Resiliency subprogram investments included in this case are tied to those laid out in the Reliability Roadmap.

Q. What projects, activities, and other types of work are included in the Resiliency subprogram?

A. Two primary investment categories are included in the Resiliency subprogram: Fractionalization and LVD Overhead to Underground conversions. Additionally, the Resiliency subprogram includes projects for the Vulnerable Communities Resiliency Plan that is primarily discussed by Company witness Duke, because these projects are primarily intended to increase resiliency in the targeted communities. Finally, in the test year the Resiliency subprogram will include work as part of the Company's Wildfire Risk Mitigation effort, which is also discussed by Company witness Duke. While the Reliability Roadmap also discusses ATR Loops as a resiliency investment, they are included in the LVD Lines Reliability subprogram because they also provide a substantial blue-sky SAIDI benefit.

Fractionalization

Q. Please explain what projects will be enabled by expenditures in the Fractionalization investment category.

A. Fractionalization is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the number of customers impacted by single contingency outages and customer exposure to outages. As the distribution system has been expanded over many years to meet the requirements of connecting new customers, there are a subset of circuits with disproportionately high customer counts and overhead line exposure, resulting in reliability and resiliency challenges due to the underlying system configuration. By investing in the Fractionalization investment category through the test period, the Company will be able to:

i. complete nine new circuits at seven existing substations;

ii. complete one new substation with three new circuits; and

iii. complete purchase order milestone payments and acquire one new mobile substation.

The mobile substation will support construction of the additional substation projects proposed in this subprogram, avoiding planned customer outages that would have otherwise been required.

FIGURE 48
FRACTIONALIZATION OF A SUBSTATION

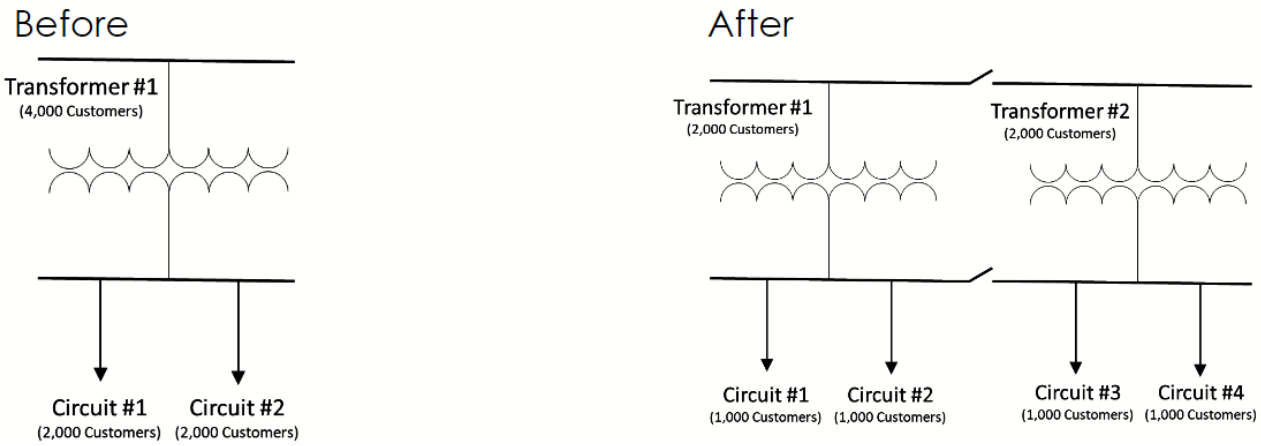
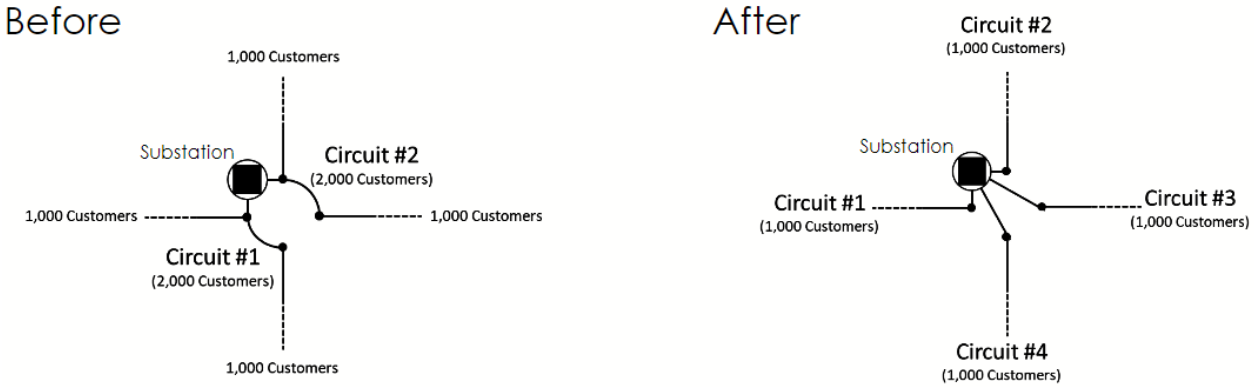


FIGURE 49
FRACTIONALIZATION OF LVD CIRCUITS



Q. What criteria are used to identify the projects for the Fractionalization investment category?

A. The Company is targeting circuits that fall into the top tiers of circuits based upon customer count and overhead line exposure. The top tiers of circuits serve more than 2,000 customers or more than 75 miles of overhead line exposure. As is shown in Figure 50 and Figure 51, there is a small percentage of circuits that are outliers with respect to customers served and miles of overhead line exposure.

FIGURE 50
CIRCUITS RANKED BY OVERHEAD PRIMARY LINE EXPOSURE

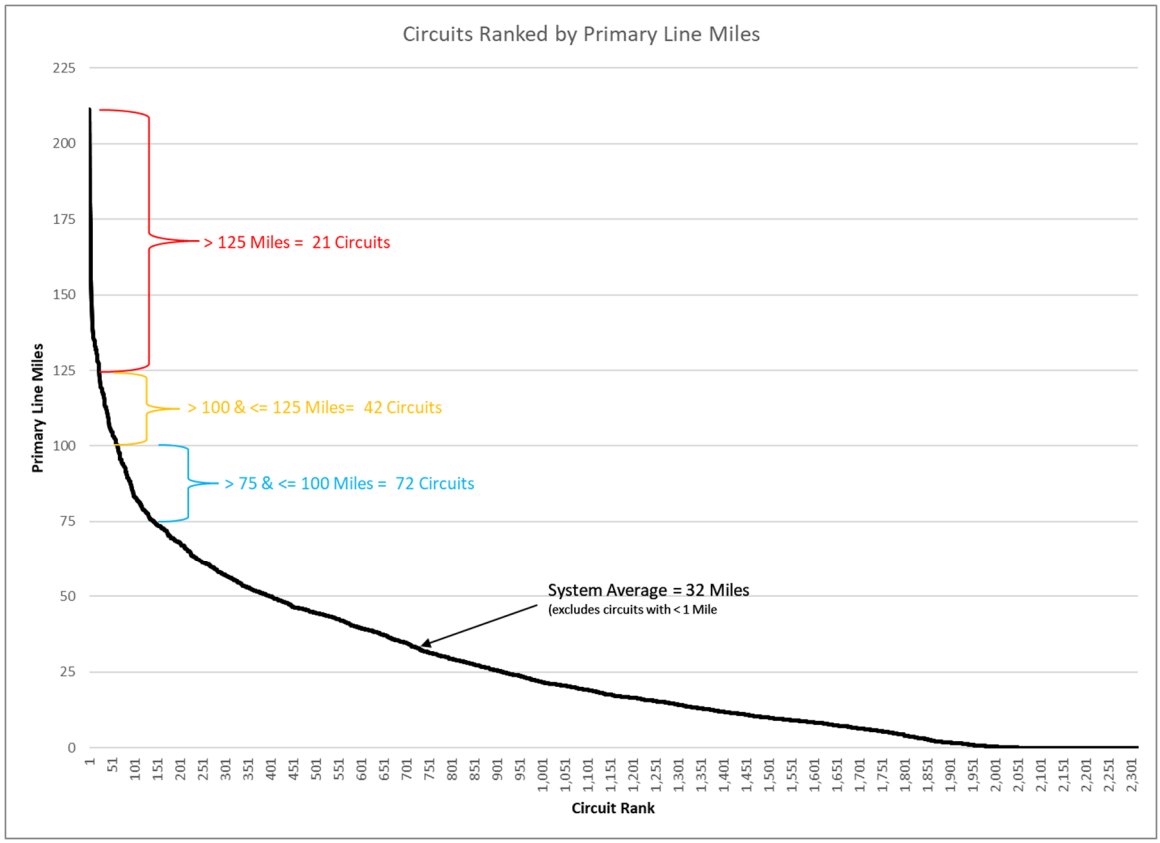
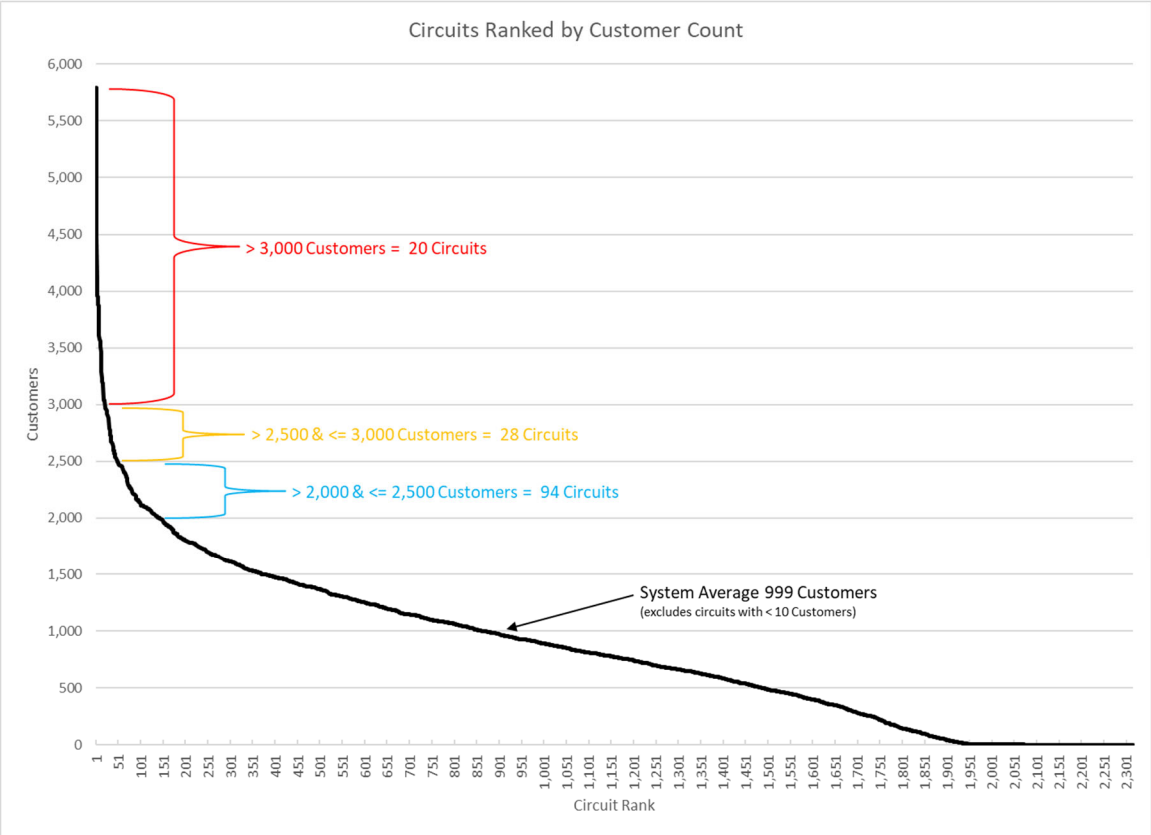


FIGURE 51
CIRCUITS RANKED BY CUSTOMER COUNT



Q. What has been the outage history for these top tiers of circuits?

A. For the years 2019 to 2023 combined, circuit outages impacting more than 2,000 customers or on circuits with more than 75 miles accounted for 848,539 customer interruptions and 402,278,560 customer-outage-minutes. Accordingly, these circuits can most benefit from Fractionalization and the improved resiliency it will provide.

Overhead to Underground Conversions

Q. Please explain what projects will be enabled by expenditures in the Overhead to Underground investment category.

A. The Overhead to Underground investment category converts sections of overhead primary LVD line to underground lines and associated equipment. This investment category does not fund undergrounding of services.

Q. Why does the Company underground LVD lines?

A. During large storm events, the Company can become inundated with LVD overhead line failure incidents. For example, in the February 2023 ice storms, the Company had approximately 10,000 reported wire downs. Experience has shown that many of these incidents are precipitated by storms blowing or breaking trees that then fall upon the LVD overhead lines, resulting in outages. The Company had similar issues with the ice storm that hit northern Michigan in March and April 2025 and again in March 2026. The icing events in 2025 and 2026 happened to overlap in impacted areas. By targeting certain overhead lines to move underground this will avoid outages on these lines caused by falling trees that fail from wind and ice.

Q. What criteria are used to identify the projects for the Overhead to Underground investment category?

A. The Company has used the following selection criteria for this investment category. The selected zones of the LVD system are single-phase; have had at least one outage in the last 24 months; serve between 10 and 200 customers; are operated at one of the three standard wye voltages; are not being considered for another reliability project; have a load after

installation of 36% or less of the ampacity of the newly installed facilities; and are located in an area that has experienced tree- or weather-related outages.

Q. Please further explain these criteria choices.

A. Single-phase was selected due to its lower cost, the typically limited number of customers who would be negatively impacted by an underground line outage, and being least susceptible to above average load growth. LVD protective zones with at least one outage in the last 24 months were selected so that there would be a more immediate reliability benefit. Limiting the customers served by the zone to between 10 and 200 ensures that the project provides benefits to more than a few customers, while limiting the impact of any outage on the underground facilities. Underground conversion of only the three standard wye voltages ensures that additional costs are neither initially incurred on the additional equipment to accommodate delta configurations nor the conversion cost to a standard wye voltage later. Similarly, selecting zones that are not considered for another reliability project avoids duplication of efforts. Ensuring that the new underground facilities are loaded to 36% or less of their ampacity provides for typical load growth without needing to replace the facility before end-of-life. Finally, underground conversions in areas that have experienced tree-related and weather-related outages helps to minimize future forestry clearing costs.

The Company has not made any changes to its selection criteria since Case No. U-21870 was filed.

Q. Do these selection criteria mean that all circuits or zones meeting these selection criteria will ultimately be converted to underground?

A. No, not necessarily. The purpose of the selection criteria is to narrow the Company's total population of LVD circuits down to a more manageable list so that it can identify locations where undergrounding is most justified. In the instant case, the Company is only seeking cost recovery related to the projects identified in Exhibits A-167 (JMP-1) and A-168 (JMP-2).

Q. How has the Company changed its plan for undergrounding since the 2025 Reliability Roadmap and Case No. U-21870 were filed?

A. In Case No. U-21870, the Company proposed to convert 50 miles of overhead line to underground in the test year in that case (May 1, 2026 through April 30, 2027). However, the Commission only approved approximately 11.5 miles of that plan in its Order in that case. Therefore, the Company is only proposing that amount of undergrounding work in the bridge period in the instant case, which aligns with the test year in Case No. U-21870. The Company is proposing 49 miles of undergrounding work in the test year in the instant case, and is essentially deferring its proposed ramp-up from the 2025 Reliability Roadmap by one year to account for the disallowance in Case No. U-21870.

Q. Has the Company assessed each of its proposed undergrounding projects against other overhead alternatives?

A. For the test year, yes, the Company has conducted benefit cost analyses for each proposed project, as directed by the Commission in the U-21870 Order. For the bridge period, the Company is simply proposing to underground the miles that were already approved by the

Commission in Case No. U-21870, as noted above, so the Company has not run further evaluations of that work.

For test year projects, the Company compared the projected cost of the undergrounding work against an overhead equivalent. For purposes of this analysis, the overhead equivalent was to rebuild the overhead line with more resilient tree wire, so the analysis used the estimated cost of a hypothetical tree wire project on the selected portion of line, and also accounted for the cost of continued line clearing work on the rebuilt line over subsequent years. The analysis also accounted for the respective reductions in outages following either an undergrounding project or an overhead equivalent, in order to account for the fact that undergrounding produces superior reliability outcomes compared to overhead work.

In this analysis, each of the identified test year undergrounding projects have a benefit cost ratio greater than 1, indicating that they are economically justified projects. This is shown in Exhibit A-172 (JMP-6). The Company will provide the parties the full details of this analysis underlying Exhibit A-172 (JMP-6) in workpaper WP-JMP-1.

Resiliency: Overall Investment and Benefits

Q. What is the Company's projected test year spending level, for which it is requesting cost recovery for the Resiliency subprogram?

A. The Company is requesting recovery of additional resiliency capital expenditures in the amount of $55,030,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 29, column (k), and $78,751,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 29, column (l).

Q. Please explain how the capital expenditures projected for the test year for this subprogram will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 52 below.

FIGURE 52
RESILIENCY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Fractionalization	$20,470,000	4 projects	$17,716,000	5 projects
Overhead to Underground	$4,560,000	11.4 miles	$19,200,000	49 miles
Vulnerable Communities Resiliency	$30,000,000	11 projects	$40,000,000	15 projects
Wildfire Risk Mitigation	$0	N/A	$1,835,000	1.2 miles/ 400 fuses
Total	**$55,030,000**		**$78,751,000**	

Q. Please identify the projects that will be completed in the Resiliency subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-167 (JMP-1), page 27, and for the test year, listed in Exhibit A-168 (JMP-2), page 14. Projected project costs were developed considering estimated costs for materials and labor and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes. The East Tawas, Eagle, Mobile Substation 27, Prescott, and Cottage Grove projects listed for the bridge period in Exhibit A-167 (JMP-1), page 27, and for the test year listed in Exhibit A-168 (JMP-2), page 14, will span multiple years due to construction scheduling, mobile substation progress payments occurring in the bridge period and test year, and transformer progress payments occurring in the bridge period and test year.

The Kent City and Wolf Lake projects listed for the bridge period in Exhibit A-167 (JMP-1), page 27, and for the test year listed in Exhibit A-168 (JMP-2), page 14 are planned in years beyond the test year but will span multiple years due to transformer progress payments occurring in the bridge period and test year.

Because it can take more than two years to obtain a single transformer, the Company has placed transformer orders ahead of time to ensure they will be available in the planned project years. The Company then makes "progress payments" on these transformer orders to ensure their timely delivery from the manufacturer. Making progress payments will allow the Company to ensure it has an adequate supply of transformers for the planned projects.

Q. How were the proposed Fractionalization projects identified?

A. The proposed Fractionalization projects will address three of the 40 highest customer count circuits, and four of the 40 highest line exposure circuits. Figure 53 identifies two of the pre-investment and post-investment configurations for these circuits benefitting more than 14,000 customers. Additional projects shown in Exhibit A-168 (JMP-2) will also address circuits with over 2,000 customers or with line exposures over 75 miles of exposure.

FIGURE 53
FRACTIONALIZATION PROJECTS STATISTICS

Resiliency Projects	Pre-Investment Configuration				Post-Investment Configuration (Estimate)				Benefit
	Substation	Circuit	Customers	Total Miles	Substation	Circuit	Customers	Total Miles	Cust-Min
Bennington Substation	Bennington	Manitou	759	53	Bennington	Manitou	759	53	76,750
	Bennington	Grand River	1390	114	Bennington	Grand River	852	63	
					Bennington		538	51	
Eagle Substation	Chicago	Chicago	1892	28	Chicago	Chicago	1892	28	249,309
	Chicago	Pinebrook	2650	33	Chicago	Pinebrook	1987	25	
	Hager Park	Wellington	948	31	Hager Park	Wellington	553	14	
	Hager Park	Hager Park	3735	58	Hager Park	Hager Park	968	32	
	Rosewood	Pioneer	1171	13	Rosewood	Pioneer	1171	13	
	Rosewood	Cottonwood	2083	22	Rosewood	Cottonwood	2083	22	
	Rosewood	Lamplighter	2241	24	Rosewood	Lamplighter	1923	20	
	Van Buren	Van Buren	1871	25	Van Buren	Van Buren	1316	17	
	Van Buren	Moss Lake	375	10	Van Buren	Moss Lake	375	10	
	Van Buren	Rush Lake	1516	36	Van Buren	Rush Lake	680	21	
					Eagle	New Circuit 1	1610	24	
					Eagle	New Circuit 2	1051	16	
					Eagle	New Circuit 3	1838	21	
					Eagle	New Circuit 4	1035	15	

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Resiliency subprogram?

A. The additional resiliency spending will provide direct and immediate reliability benefits to customers connected to the projects. These projects will better prepare the LVD system for the increasing frequency and severity of wind gusts and storms. The LVD system is most at risk of experiencing failures from severe weather. Therefore, the resiliency spending will reduce the quantity of outages or the extent of the LVD system impacted during an outage.

Q. How will the identified Fractionalization projects improve resiliency?

A. Fractionalization will address recovery and prevention by dividing the system into smaller portions, reducing the number of customers experiencing an outage for a single failure; and reducing the customers' miles of exposure to overhead line outages, preventing outages to customers that would have otherwise been interrupted.

Fractionalization will also provide operational switching opportunities, allowing for improved fault isolation and faster restoration of customers prior to the completion of

repairs, also enabling a quicker recovery from the outage. An ancillary benefit of Fractionalization is increased system capacity, available for both increased load and renewable resource hosting capacity.

Q. How will the identified Overhead to Underground projects improve resiliency?

A. Investing in conversion of LVD overhead lines to underground will increase both survivability and prevention. Underground LVD lines are expected to survive nearly all tree-caused and ice-caused failures preventing outages during major storm events. The Company's experience has shown that the greatest cause of interruptions on the LVD system is due to trees. Winter storms with ice also cause outages during major events. EPRI research and benchmarking with the WEC Energy Group have found that undergrounding is highly effective at hardening the distribution grid from storm damage and reducing interruptions.

The picture in Figure 54 provides an example of the types of incidents that can be avoided if lines are placed underground. In this instance, a tree has fallen on the line in an area that will be difficult for crews to reach, because it is located in the woods with snow cover.

FIGURE 54
TREE ON OVERHEAD SINGLE-PHASE PRIMARY LINE



Q. Please summarize the benefits customers will realize through the Company completing work, at the requested spending level, in the Resiliency subprogram.

A. With fewer line miles for line workers to patrol and repair to restore service due to fractionalization and with fewer LVD line failures overall due to overhead-to-underground conversions, there will be less restoration work time required, providing more time for line workers to complete other restoration work, resulting in a quicker restoration overall. Simply put, faster restoration and recovery from an event result in shorter electric interruption durations, benefiting all storm-impacted customers.

The direct customer benefits for the projects are identified in the Benefit Type and Benefit columns of Exhibits A-167 (JMP-1), page 27, and A-168 (JMP-2), page 14. Types of benefits identified on the exhibits, and summarized in Figure 55, include:

FIGURE 55
RESILIENCY BENEFITS SUMMARY

Investment Category	Benefit Categories	Bridge Period	Test Year
Fractionalization	Customer-outage-minutes avoided	798,564	5,329,684
Overhead to Underground	Customer-outage-minutes avoided	377,871	1,626,072
Vulnerable Communities Resiliency	Customer-outage-minutes avoided	3,050,021	3,879,428

Capacity Program

Q. What portion of the Capacity Program will your testimony discuss?

A. The Capacity Program is designed to ensure the distribution system can serve the electric peak demand, keep the system within acceptable voltage ranges, and support the Company's CVR subprogram. Company witness Duke further discusses this program. This testimony will focus on the LVD subprograms:

(i) LVD Lines Capacity;

(ii) LVD New Business Capacity; and

(iii) CVR.

Projected spending is explained in greater detail in the subprogram sections below.

Q. Does the Company use AMI data in its planning process?

A. Yes. The Company's AMI system collects the total kWh delivered, total kWh received, the total kilovolt-amperes-reactive-hours ("kvarh") delivered, total kvarh received, and average voltage over the meter reading interval, which can be hourly or every 15 minutes,

depending on the meter. The Company uses AMI data to identify the frequency and length of customer outages, and that information is used to inform and focus distribution planning. Additionally, kVA values in the Customer Loads database are derived from monthly AMI billing consumption data, and used by the Company's distribution power flow model, CYME, for purposes of modeling load at the customer level. The Company uses CYME[4] power engineering software to analyze loading on the distribution system. Company witness Scott A. McPhail's testimony discusses a Planning Systems Modernization project that is needed to enable the full time-series benefits of AMI datasets in CYME.

Q. Does the Company consider Non-Wires Solutions ("NWS") in its planning processes?

A. Company witness Duke discusses the Company's current position on NWS in her direct testimony. The Company is developing a new NWS pilot in 2026 that it plans to submit outside of the regular rate case process in the Commission's expedited pilot process.

LVD Lines Capacity

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Lines Capacity subprogram.

A. Capital investments in the LVD Lines Capacity subprogram address and reduce overload risk on components of the LVD lines system. All components on the system have a rating for their maximum designed load, and while any individual component can withstand loading to greater than 100% of this level for a short time, overloads that are too long or too frequent lead to deterioration and increased risk of failure. Investment in this subprogram responds to risks that already exist due to load growth or load shifting from one area of the system to another. These investments fund critical projects to address

[4] CYME is the trade name of the software, which was previously named Chinh Yvan Micro Engineering.

capacity loading issues in accordance with planning criteria and to address new distributed load additions to ensure that the LVD system can accommodate projected distribution loads. Investments in this subprogram are divided into two categories: equipment upgrades and lines capacity projects associated with substation projects.

Q. Why does the Company invest in LVD Lines Capacity projects to upgrade or replace overloaded lines and equipment?

A. The Company upgrades or replaces overloaded lines and equipment to reduce reliability and safety risks, including equipment failure; nuisance disruptions of sectionalizing devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential risk of fire; inadequate voltage to downstream customers; and conductor melting or sagging creating a public safety hazard of potential contact. Additionally, fixing overload risks on the LVD system better positions the system to accommodate future growth of EV charging, heating electrification, and other customer adoptions of new technologies.

Q. Why does the Company invest in LVD Lines Capacity projects associated with substation capacity projects?

A. Substations are part of the backbone infrastructure of the electric distribution network; therefore, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation equipment reaching capacity limits. When an increase in the transformer equipment size is not a reasonable alternative, other solutions implemented may include a new substation with LVD line upgrades or line extensions that transfer customers to other nearby circuits to reduce the load on the existing substation equipment. This ability to transfer customers to another circuit will be vital for the Company's Distribution Automation program discussed by Company witness McPhail.

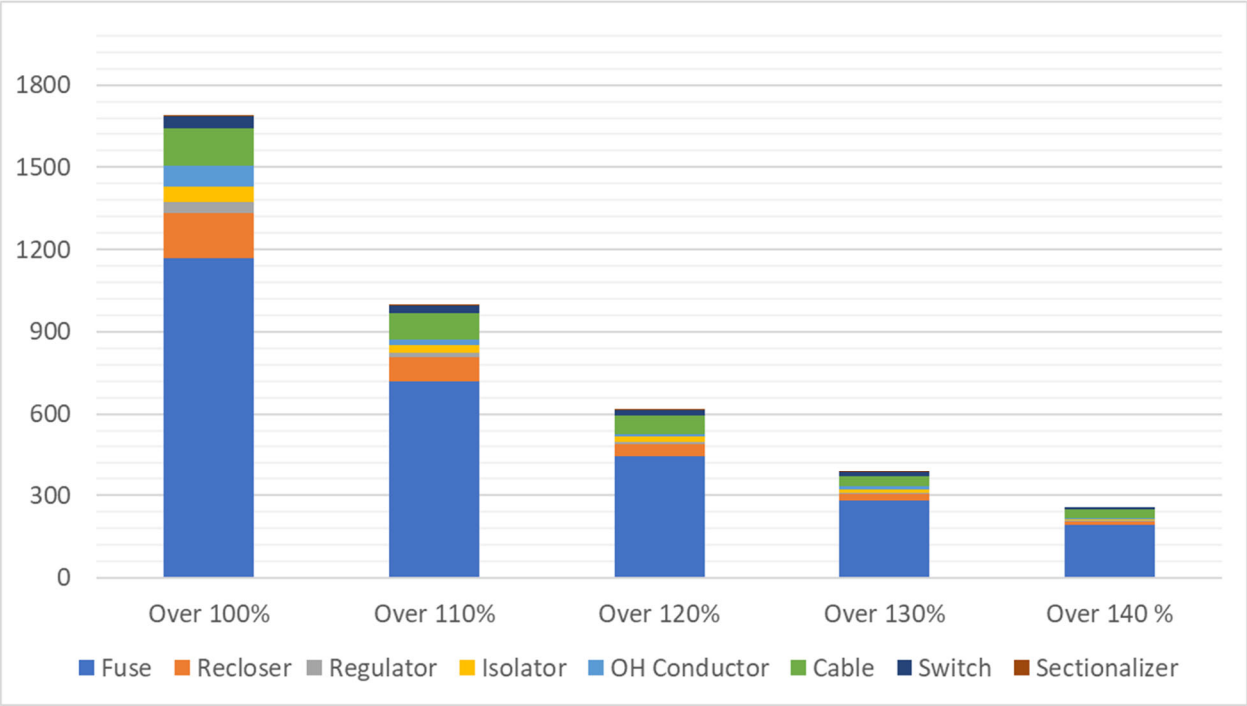
Q. How are projected LVD Lines Capacity subprogram expenditures aligned with the Reliability Roadmap?

A. The projected expenditures are tied to the LVD Overload Risk Reduction plan outlined in the Reliability Roadmap. As the LVD Overload Risk Reduction plan describes, the Company has a significant population of assets that are loaded to greater than 100% of their rating. In the highest-risk situations, assets are loaded to much greater levels than their respective ratings. In the 2023 Reliability Roadmap, the Company outlined an initial plan to address these overload issues, and the bridge period and test year investment in the instant case are aligned with the levels established in that plan. The plan defined in the Reliability Roadmap is intended to address all components overloaded beyond 100% of their rating in order to eliminate overload-caused outages on the LVD system. Each equipment type is prioritized into minor, moderate, and high-risk categories for failure based on industry loading guidelines, as shown in Figure 56 below; all types of equipment begin to face risk once their loading exceeds 100%. The most recently available loadings on the Company's system are shown in Figure 57 below.

FIGURE 56
OVERLOAD RISK BY EQUIPMENT TYPE

Equipment Type	Minor Risk of Overload Failure (% of Nameplate)	Moderate Risk of Overload Failure (% of Nameplate)	High Risk of Overload Failure (% of Nameplate)
Overhead Conductor	100%	110%	120%
Underground Cable	100%	115%	130%
Reclosers	100%	125%	150%
Isolators	100%	110%	120%
Switches	100%	110%	120%
Fuses	100%	130%	140%
Regulators	100%	110%	120%
Sectionalizers	100%	110%	120%

FIGURE 57
QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, 2024



Q. Did the Company consider any alternatives to this approach?

A. Yes. The Company could continue to allow assets on its system to be regularly overloaded, but this simply magnifies risk to the system, especially in situations in which summer temperatures and, therefore, summer cooling load continue to increase. It is more prudent to address overload risks proactively. With that in mind, the Company does work to develop projects that will best address overload risk from among available alternatives. Projects in this subprogram are developed by the LVD circuit planners to address the identified capacity issues. They identify the best method of improving the issue using the various approaches described above. The Company prioritizes capacity projects based primarily on overload level and equipment type, addressing the highest overloads prior to lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact.

Q. How does the Company identify capacity issues that would require an LVD Lines Capacity project?

A. The Company's project selection follows three steps:

(i) considering peak loads;

(ii) comparing peak loads to failure criteria; and

(iii) ranking components by their percentage of overload based on equipment type.

Q. What is the significance of considering peak load in this subprogram?

A. All planning activities in this subprogram are based on projected peak load conditions, which is when capacity is most challenged. The Company uses normal or continuous ratings for peak load conditions, due to the heightened risk of equipment failure or degradation when operating above the capability rating. The loadings on equipment are established by the manufacturer or by a recognized industry source such as the Institute of Electrical and Electronics Engineers, and specify the optimal operation of the equipment based on the capability characteristics of the components. The specific evaluation of each piece of equipment depends on its use. For example, equipment using oil is rated based on a temperature limit not to be exceeded. If that operating temperature is exceeded, then the equipment can start to break down and possibly lead to a shorter lifespan. Other equipment has a defined set of characteristics that, when taken beyond the manufacturer specifications, can lead to a change in characteristics of the material, altering its strength and durability.

Q. Please describe the Company's power flow study process to evaluate the LVD system's ability to handle peak loads.

A. The Company evaluates the LVD system using CYME, an industry-standard power flow software, to perform a power flow analysis. CYME uses load information from two databases to perform power flow studies: the Feeder Demand database and the Customer Loads database. The Feeder Demand database provides the maximum amperage experienced on the circuit with data from substation metering equipment. The Customer Loads database uses customer meter data. The CYME power analysis compares the Feeder Demand load at the substation to the Customer Load distributed across the circuit to determine power flow, voltages, and system protection needs. This analysis is performed on present and future states of the system. This process identifies overloaded distribution equipment and instances of unacceptably low or high voltage during system peak load conditions.

Q. How often does the Company conduct these power flow studies?

A. The Company annually evaluates loading on its LVD distribution equipment, using CYME, for capacity planning purposes. Additionally, studies are completed throughout the year to address emergent issues such as load transfers, generator interconnections, new customer load additions, and reliability failures.

Q. After the power flow study is performed, how does the Company determine if an LVD Lines Capacity project is required?

A. Capacity planning criteria requires that a component of the distribution system have a projected load higher than its capacity, based on Company standards for capacity, before developing a potential capacity project. At present, this requires that a component of the

distribution system experience a load more than its capacity a minimum of one year prior to a capacity project being initiated.

Q. What other factors does the Company consider when determining if an LVD Lines Capacity project is required?

A. Previous year loadings and future customer growth are considered when projecting future loadings. While most equipment has emergency ratings that enable higher capacity for short durations, these are not considered during capacity planning, since loading at these higher levels results in degradation and eventual failure.

Q. Has the Company considered the impact the adoption of EVs may have on its LVD system?

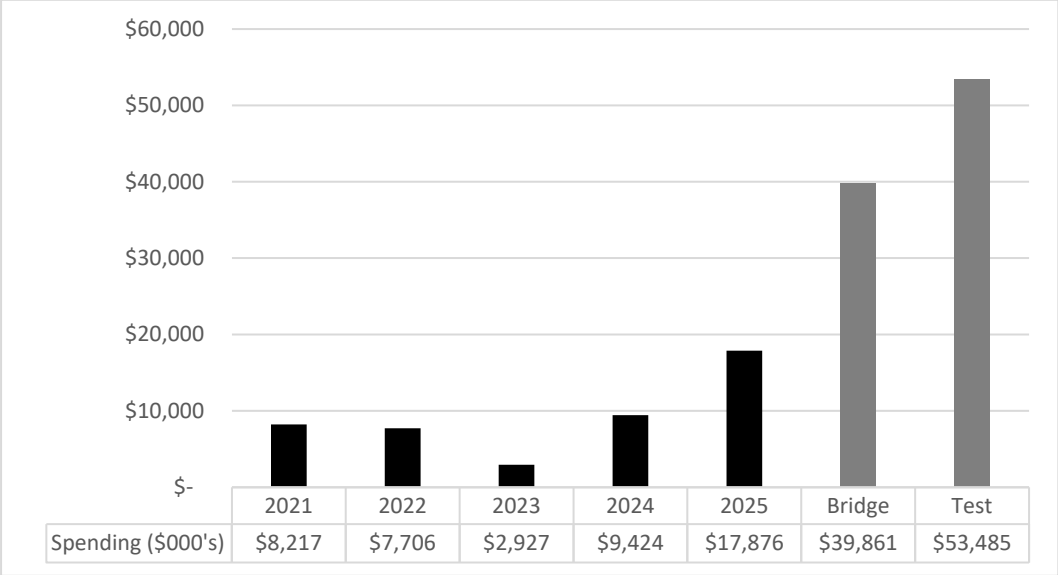
A. Yes. As the Company continues to support EV growth as described by Company witness Alex M. Gast, the first step to understanding LVD system impact is to predict when and where EVs will charge. To that end, the Company has conducted an EV propensity study in the past to consider potential concentration of at-home residential charging on certain circuits, which was discussed in detail by Company witness Donald A. Lynd in Case No. U-21585. To date, this is still the most recent propensity study conducted by the Company. Note that larger scale charging is expected to be a spot load and be addressed through the Company's LVD Lines New Business and LVD New Business Capacity subprograms. Company witness McPhail discusses the need for a Planning Systems Modernization to enhance the Company's ability to forecast and simulate the impacts of EVs, heat pumps, and other customer technology adoption on the distribution system. This initiative is necessary to integrate various propensity studies, including EVs such as the one mentioned

above, with the CYME software as a regular and repeatable step in the capacity planning process.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Capacity subprogram?

A. The Company is projecting LVD Lines Capacity capital expenditures of $39,861,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 31, column (k), and $53,485,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 31, column (l). The Company's historical actual spending in the LVD Lines Capacity subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 31, and below in Figure 58. As discussed above, the increase in spending relative to historical levels is aligned with ramping up to the Company's goal of addressing all assets loaded beyond their ratings.

FIGURE 58
LVD LINES CAPACITY SUBPROGRAM EXPENDITURES



	2021	2022	2023	2024	2025	Bridge	Test
Spending ($000's)	$8,217	$7,706	$2,927	$9,424	$17,876	$39,861	$53,485

Q. Can you further explain the pace of the Company's proposed LVD Lines Capacity investment ramp-up in the instant case?

A. In its U-21870 Order, page 103, the Commission stated that it "encourages the Company to provide accurate projections that reflect a pace of work that Consumers is capable of accomplishing. In the next rate case, the Commission expects to see Consumers show that it actually spent the approved amounts on this worthwhile program." In 2024 and in earlier years, LVD Lines Capacity investments were lower than proposed amounts. However, in 2025, the Company substantially increased its investment level from where it had been in 2024. In the bridge period in this case, the Company plans to continue this pace of investment increase (with 2026 spending aligned with levels approved by the Commission in Case No. U-21870), with a further increase in the test year to get to the levels established in the Reliability Roadmap. This pace of increase represents a reasonable phasing in of Reliability Roadmap levels.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 59.

FIGURE 59
LVD LINES CAPACITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Overloaded equipment upgrades	$39,095,000	164	$45,801,000	204
Lines capacity projects assoc. w/ substation work	$766,000	1	$7,684,000	5
Total	**$39,861,000**	**165**	**$53,485,000**	**209**

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Capacity subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-167 (JMP-1), pages 28 through 30, and for the test year, listed in Exhibit A-168 (JMP-2), pages 15 through 18. The Company developed the projected costs of the projects in these exhibits considering estimated costs for materials and labor, and the Company's previous experience performing similar projects. These exhibits also identify the location and benefits of the projects.

Q. Please explain the year-over-year historical variation in spending in this subprogram.

A. In 2023, a modest increase in LVD New Business Capacity as well as increases in LVD New Business, Asset Relocations, and Demand Failures work required the Company to shift resources away from LVD Lines Capacity to focus on work within those subprograms. In 2025, the Company began increasing its investment in this subprogram as it began executing the work outlined in the Reliability Roadmap.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Capacity subprogram?

A. This subprogram prevents future failures that would increase SAIDI if they occurred. The investments made to upgrade overloaded assets and alleviate voltage issues increase the longevity of the equipment and prevent service issues and interruptions to customers while improving employee and public safety. The benefits of each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibit A-167 (JMP-1), pages 28 through 30, and for the test year, listed in Exhibit A-168 (JMP-2), pages 15 through 18.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project in this subprogram. There is a wide variance among work required, ranging from $2,000 for a protective device upgrade to $2,000,000 or more for a multi-mile voltage conversion project. Please note that, while voltage conversion projects in LVD Lines Reliability are intended to reduce non-standard voltages, the voltage conversion projects in this subprogram are typically going from one standard voltage to another standard voltage to support growing load in the area, and to match voltages on neighboring substations for load transfer and automation capabilities. An example is 4.8/8.32 kV wye to 7.2/12.47 kV wye.

In the instant case, the bridge period and test year both include multiple individual projects that cost more than the historical per-project average, which causes the apparent per-project unit cost to be higher than it was historically. Many past LVD Lines Capacity projects were relatively simple, and therefore less expensive; now, the Company is planning multiple larger projects that have correspondingly higher costs. For example, in the test year, the Company has identified the following projects that cost in excess of $1 million:

- DARE VALENTINE SUB - $4.038 million: A new 24.9 kV distribution substation is being built to provide additional capacity for the surrounding area and eliminate loading concerns for surrounding substations. This project will require approximately 6 miles of new 3-phase line extensions to tie to existing lines in the area to transfer larger customer loads to the new substation feeders. The high amount of LVD work required to connect to the existing substations in the area drives the total project cost to be higher than normal for projects of this type.

- DARE RANGER LAKE_GOODAR LCP 185 – $2.482 million: Multiple oil-cooled reclosers in series are overloaded up to 127% of nameplate. The proposed solution requires a 4.1-mile phase extension to allow for load balancing. Part of this project will also include reconductoring from bare wire to covered tree wire in heavily wooded areas to help improve overall system reliability. Adding additional phasing will require almost 100% pole replacement to meet pole loading criteria.

LVD New Business Capacity

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD New Business Capacity subprogram.

A. Equipment and lines need to be added or upgraded for new customers or to maintain adequate service to existing customers when they increase their load beyond existing capacity. Projects in the LVD New Business Capacity subprogram are generally similar in scope to projects in the LVD Lines Capacity subprogram. Because work in this subprogram is driven by customer requests, the Company does not plan or prioritize projects far in advance in this subprogram.

Q. Is there a specific timeframe that the Company needs to complete a New Business Capacity project?

A. Yes. Each new business capacity project needs to be constructed on the same timeframe as the customer load addition that is driving the project to avoid overload of the LVD system. Accordingly, the Company has little latitude on whether to delay or defer these new business capacity projects.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD New Business Capacity subprogram?

A. As with other Capacity subprograms, work in the LVD New Business Capacity subprogram ensures the reliable distribution of electricity to customers by preventing overloads on the system that can cause outages and poor voltage service. The LVD New

Business Capacity subprogram provides the added benefit of allowing customers, particularly in the commercial and industrial ("C&I") sectors, to expand their activities and drive economic growth in Michigan. Although spending in the LVD New Business Capacity subprogram is not explicitly tied to the LVD Overload Risk Reduction plan in the Reliability Roadmap, work in this subprogram does increase the capacity of the system, which thereby reduces the risk of future overloads while accommodating new customer loads.

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD New Business Capacity subprogram.

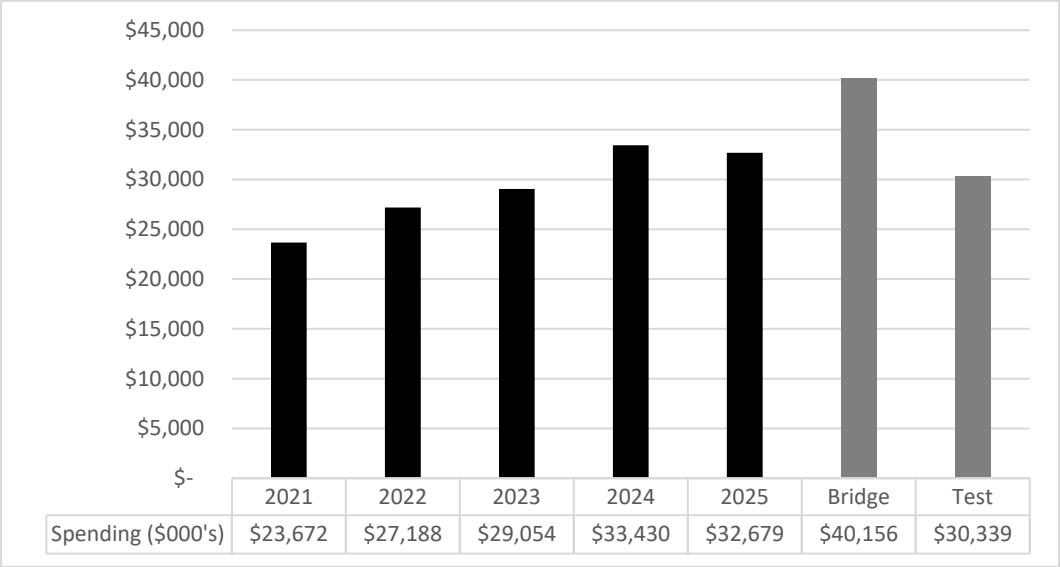
A. The Company has identified projects for the bridge period, which are listed in Exhibit A-167 (JMP-1), pages 31 through 34. Due to the nature of the New Business Capacity subprogram, only projects known in advance are listed. Accordingly, the bridge period list is not a complete list of all work that will be performed, and the Company is not yet aware of specific projects for the test year. The Company developed the projected costs of the projects in this exhibit considering estimated costs for materials and labor, and the Company's previous experience performing similar projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD New Business Capacity subprogram?

A. The Company is projecting LVD New Business Capacity capital expenditures of $40,156,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 34, column (k), and $30,339,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 34, column (l). The Company's historical actual spending in the LVD New Business Capacity

subprogram, along with the bridge period and test year projections, are shown in Exhibit A-87 (EMD-3), line 34, and below in Figure 60.

FIGURE 60
LVD NEW BUSINESS CAPACITY SUBPROGRAM EXPENDITURES

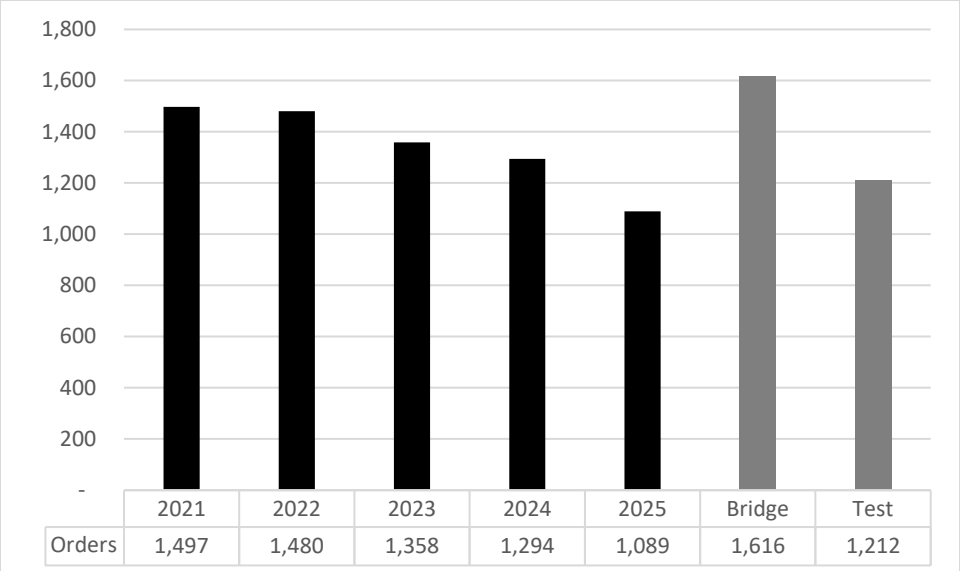


Q. How did the Company develop its projected expenditures in this subprogram?

A. LVD New Business Capacity work is based on customer-driven needs; therefore the Company bases its spending projections on historical actual spending with adjustments for observed trends. The Company has been experiencing an increase in spending on LVD New Business Capacity in recent years. Note that the projected bridge period and test year investment levels represent a modest increase from the five-year average, but they are on par with the Company's 2024 actual investment level and lower than the 2025 actual level (on an annual basis). The number of new business capacity orders per year increased from 1,212 in 2020 to an average of 1,247 over the last three years. The Company anticipates future per order costs for the bridge period and test year to be similar to costs experienced in 2024 and 2025. The Company projects it will complete 1,616 orders in this subprogram in the bridge period.

The spending amount for the test year was determined based on the anticipated number of orders in the test year. The Company projects it will complete 1,212 orders in this subprogram in the test year. The historical and projected number of orders is shown in Figure 61 below.

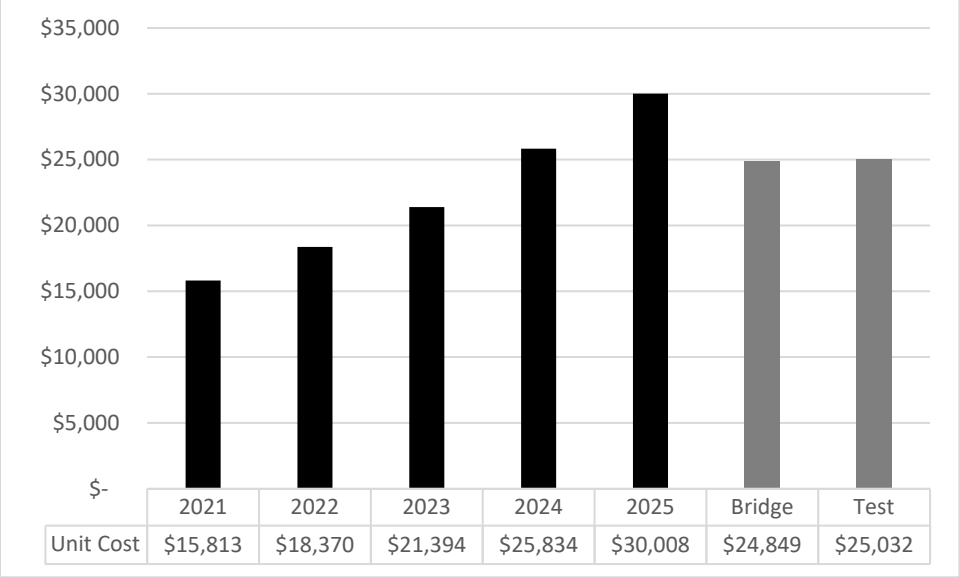
FIGURE 61
LVD NEW BUSINESS CAPACITY UNITS



Q. What are the historical unit costs for the LVD New Business Capacity subprogram?

A. The historical and projected unit costs of LVD New Business Capacity orders are provided in Figure 62 below.

FIGURE 62
LVD NEW BUSINESS CAPACITY HISTORICAL UNIT COSTS



Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. Yes, for the overall subprogram. There is a variance of costs among the different projects required ranging from $1,000 for a protective device upgrade to as high as $1,100,000 for the LVD work associated with the construction of a new substation. However, because of the volume of units, an average unit cost can be used to develop the spend projections for the overall subprogram.

Conservation Voltage Reduction

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the CVR subprogram.

A. CVR is the capability to optimize service-point—or customer meter voltages—to reduce energy demand without requiring active participation or specific investment by customers. CVR uses a set of technologies, including Volt-VAR Optimization, that reduces the

delivery voltage along LVD circuits, thereby reducing the amount of electric load that must be served on the LVD circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements. CVR was part of the Company's 2018 Integrated Resource Plan ("IRP") in Case No. U-20165, which was approved by the Commission in 2019, and the 2021 IRP in Case No. U-21090, which was approved by the Commission in 2022. This subprogram of the Capacity Program funds capital projects necessary for implementing the Company's overall CVR plan that is included in the IRP.

Q. What is included in these capital projects?

A. The purpose of these projects is to install and upgrade equipment to ensure that the targeted LVD circuits can enable CVR without providing voltage to customers outside the allowable range. These projects include installing Distribution Supervisory Control and Data Acquisition ("DSCADA"), regulator controllers, and capacitor controllers on targeted circuits, as well as work to address potential voltage issues. The Company uses AMI data to determine voltage levels being provided to customers; if a customer's existing voltage is outside the range that would allow CVR optimization, the Company will complete circuit conditioning work, including but not limited to transformer upgrades, line reconductoring, as well as other solutions to improve the voltage.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the CVR subprogram?

A. The benefits of CVR were discussed in the Company's IRP filings in Case Nos. U-20165 and U-21090. In those filings, the Company forecasted that CVR would provide energy and demand savings, as well as loss reduction, as shown in Figure 63. The amount of energy savings for each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibits A-167 (JMP-1), page 35, and A-168 (JMP-2), page 19.

FIGURE 63
CVR CUMULATIVE ENERGY AND DEMAND SAVINGS

	Actual[5]							Projected[6]			
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Cumulative Peak MW Reduction	0.4	5.6	14.7	21.2	39.1	47.8	53	72	82	94	
Cumulative MWh Reduction	82	5,643	23,882	69,045	125,746	190,417	272,137	169,894	194,227	219,058	24

Q. How does the Company ensure proper measurement and verification of CVR performance?

A. When the Company initially began enabling CVR on LVD circuits in 2019, the Company tested CVR performance by cycling CVR on and off on successive days and using substation DSCADA data and customer smart meter data to measure actual CVR savings by comparing data when CVR was on versus when it was off. This initial testing creates a baseline for CVR performance. Once CVR is fully enabled and operational on a circuit, the Company's DSCADA and meter data provides sufficient telemetry to ensure

[5] Actual data from Case No. U-20165, Annual Cost Reports, Exhibit 2, columns (o) and (q), Total row.
[6] Projected data from Case No. U-21090, Exhibit A-86 (MSH-1).

continuous measurement and verification of CVR performance. A third-party evaluator has also verified that the methodology and the results obtained from the Company's analysis are valid and that it is reasonable to assume similar results will be obtained from additional circuits as CVR is enabled. The full report of the third-party evaluator is provided in Exhibit A-169 (JMP-3).

Q. How does the Company identify CVR projects?

A. CVR circuits are selected primarily based on customer types and circuits with smart grid capabilities. Smart grid equipment will eventually be available on approximately 85% of the LVD circuits; therefore, circuits that are not cost-effective for DSCADA deployment are ruled out from CVR consideration. Additionally, circuits that contain primarily C&I customers were removed. The principal reason for this is that industry analysis has shown that CVR is more effective on residential load types. From within this circuit candidate pool, circuits are selected based on those that had lower anticipated costs. For example, circuits that have already deployed the necessary upgrades to substation and line equipment were prioritized. Additionally, circuits where less capital investment would be required, as determined by a power flow study, were prioritized. The power flow study process also identifies the various projects needed to enable CVR for each circuit.

Q. Please identify the projects that will be accomplished with the requested spending level in the CVR subprogram.

A. The Company has identified upgrades to 60 circuits for the bridge period, listed in Exhibit A-167 (JMP-1), page 35, and 50 circuits for the test year, listed in Exhibit A-168 (JMP-2), page 19. The Company developed the projected costs of the projects in these exhibits considering estimated costs for materials and labor, and the Company's previous

experience performing similar projects. These exhibits also identify the location and benefits of the projects.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the CVR subprogram?

A. The Company is projecting CVR capital expenditures of $3,868,000 for the bridge period, as shown in Exhibit A-87 (EMD-3), line 26, column (k), and $2,429,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 26, column (l). This level of spending will enable the Company to add CVR to 60 circuits in 2026 and 50 circuits in 2027. It also includes $500,000 in both the bridge period and the test year to address identified low-voltage issues and customer complaints. This spending is designed to implement the Company's CVR plan, as originally proposed and approved in Case No. U-20165, subsequently updated, and approved in Case No. U-21090.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance among work required ranging from $5,000 to as high as $400,000 per project.

Metering and Transformers

Q. What will the Meters and Transformers portion of your testimony discuss?

A. This section will address the Company's single purchase plans for LVD Metering and LVD Transformers. Projected spending and benefits are explained in detail in the sections below.

LVD Metering

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Metering subprogram.

A. The LVD Metering subprogram supplies meters and associated equipment including meter sockets, metering transformers, and meter testing equipment. Historically, LVD Metering expenditures were allocated between the New Business and Demand Failures programs, but LVD Metering has always operated through a single purchase plan, and in this filing the Company has combined them into a single subprogram under Demand Failures. Meter Sockets and Electric Capital Meter Test Equipment costs are allocated across the total meter and metering transformer units to determine the overall cost per unit for this subprogram.

Q. How are the projected LVD Metering expenditures aligned with the Reliability Roadmap?

A. Following the Commission's March 1, 2024 Order in Case No. U-21389, the Company decided to defer replacement of 4G LTE meters to a later date. The Company's 4G LTE communications network provider has not provided a definitive date for the retirement of the 4G LTE network, but expects to maintain the network into the mid- to late-2030s. With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations. By year-end 2026, the Company expects to have defined an approach for eventually replacing 4G meters.

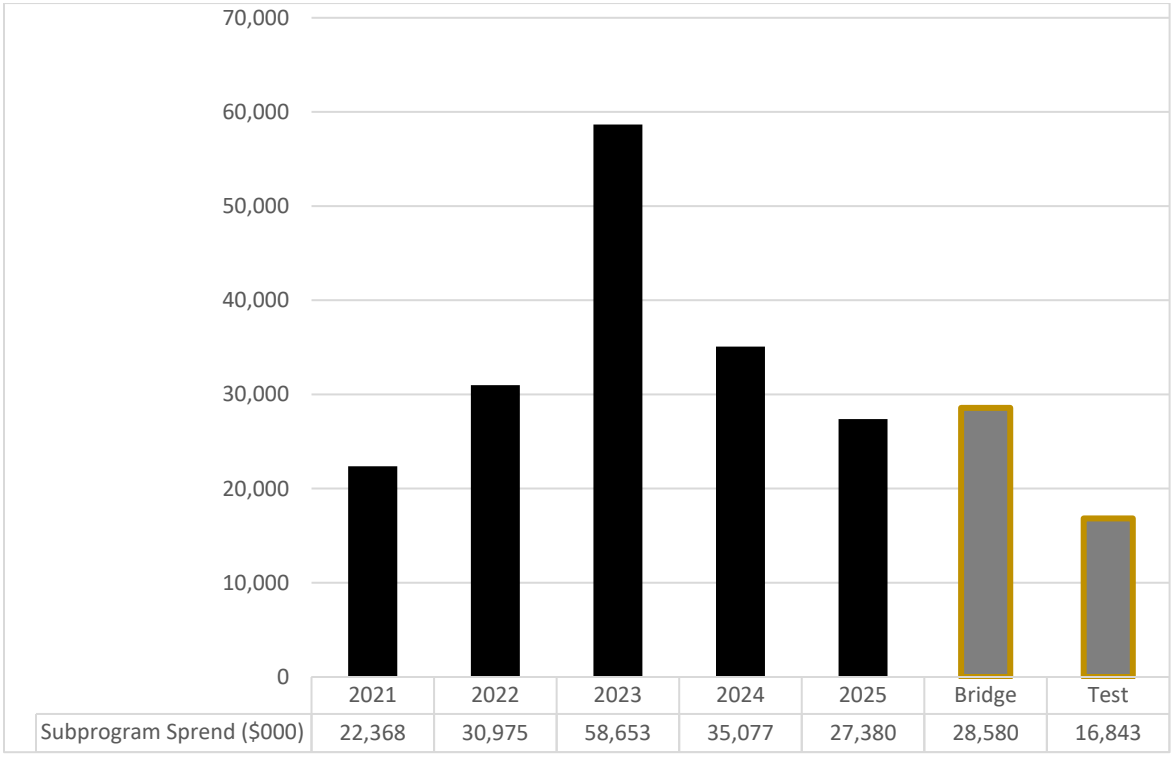
Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Metering subprograms?

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each of the metering subprograms as identified in Figure 64 below. The projections for LVD Metering capital expenditures are shown in Exhibit A-87 (EMD-3), line 9, columns (k) and (l). The Company's historical actual spending in the LVD Metering subprograms, along with the bridge period and test year forecasts, are shown below in Figure 65.

FIGURE 64
METERING EXPENDITURES AND UNITS

Subprograms	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Distribution Meter Purchases	**$28,580,000**	**43,517**	**$16,843,000**	**9,983**

FIGURE 65
LVD METERING SUBPROGRAMS TOTAL EXPENDITURES



Q. How did the Company develop its projected expenditures in the LVD Metering subprogram?

A. Expenditures are based on projected activity in the New Business and Demand Failures subprograms, which is in turn based largely on historical data. The Company also considers estimates of new business connections in future years and forecasted large project work.

Q. What benefits will customers realize through the Company completing work in the LVD Metering subprogram?

A. Metering is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, as well as to replace failed equipment through the overall Demand Failures Program. Additionally, advanced metering is an essential component in many of the Company's present and future demand response and renewable programs.

The New Business subprogram, in combination with the Demand Failures subprogram, maintains metering accuracy by replacing meters in-service that are nonfunctional, damaged, or whose accuracy has been questioned by the customer. New meters are tested upon purchase to ensure meters being deployed to new business and demand failure locations are compliant with accuracy requirements.

Q. What are the historical unit costs for the LVD Metering subprograms?

A. Historical unit costs for the LVD Metering subprograms are provided in Figure 66 below. Note for 2021, 156,960 smart meters were replaced as part of the 3G to 4G-CatM1 changeout project; the replacement meter came with new functionality, the ability to communicate with gas meters, at a cost of $7 per meter. This increased functionality allows

all the Company's smart meters to communicate with gas meters, allowing the meters to be used throughout the service territory. Including these meters in the subprogram unit cost calculation skewed the unit cost for 2021 to $109. If these units are not included in the unit cost calculation, the unit cost for 2021 is $432. This skewing also occurred in 2022, though to a smaller extent, from $541 to $253 per unit.

The table in Figure 66 breaks out the categories of purchases included and the associated unit costs for each category. There are no units for meter sockets and meter test equipment as many of the costs in those categories are minor materials; the total cost of meter sockets and test equipment are allocated across the total units of the other categories. During the bridge period and test year, the overall unit cost is being impacted by several factors. For legacy meters, the Company is purchasing higher cost units for C&I applications, to accommodate those customers' complex billing and data requirements. The increase in metering transformer units, meter socket spending, and polyphase smart meter purchases are related to conversions of 400-amp services from present configurations to instrument transformer rated installations. Presently, any meter work at these locations requires de-energization to do the work safely. Transitioning these to transformer rated installations will increase safety for Company employees and customers.

FIGURE 66
LVD METERING UNITS AND UNIT COSTS

	2021	2022	2023	2024	2025	Bridge	Test
Legacy Meters							
Legacy Units	480	101	240	420	600	1,319	992
Unit Cost	$105	$1,359	$149	$1,033	$444	$1,830	$1,491
Smart Meters							
Smart Meter Units	41,339	50,125	97,784	64,749	42,912	37,071	5,136
Unit Cost	$293	$371	$366	$223	$285	$334	$655
3G/4G Replacements							
3G/4G Units	161,284	67,440	44,760				
Unit Cost	$20	$18	$208				
Metering Transformers							
Transformer Units	2,603	4,770	5,090	5,985	8,632	5,127	3,855
Unit Cost	$1,842	$1,759	$1,743	$988	$1,741	$1,501	$1,485
Meter Sockets & Test Equipment							
Spending	$2,244	$2,642	$3,763	$2,974	$4,407	$5,585	$4,199
Allocated Unit Cost Impact	$11	$22	$25	$42	$57	$134	$421
Total Subprogram							
Total Units	205,706	122,436	148,874	71,154	52,144	43,517	9,983
Total Unit Cost	$109	$253	$390	$493	$463	$651	$1,479

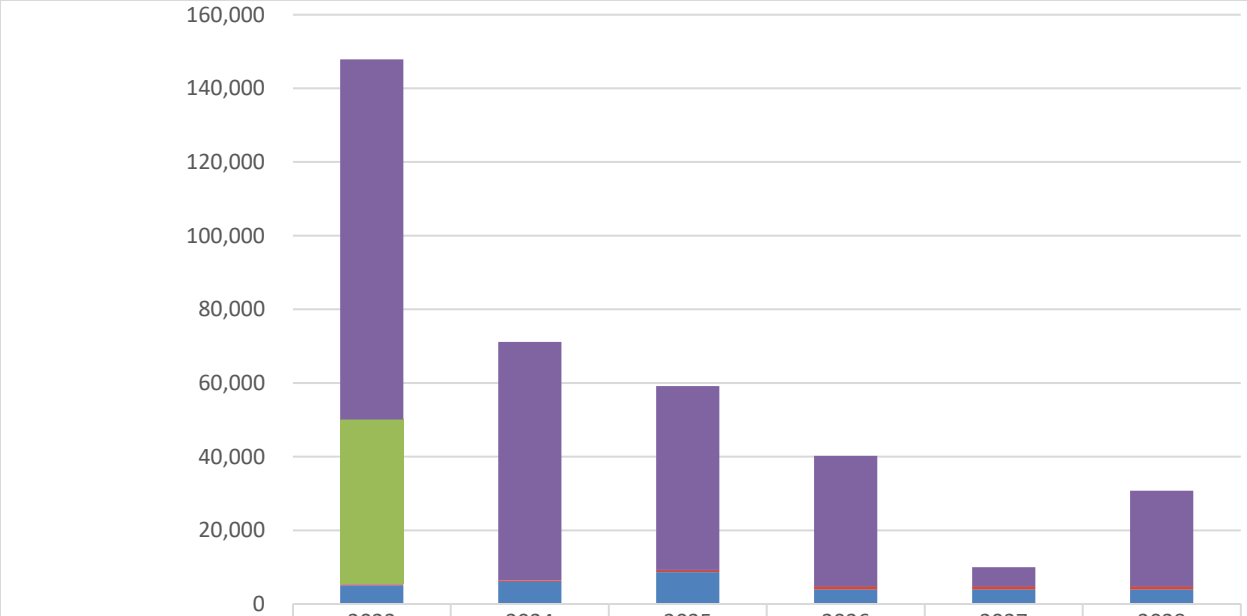
Q. Please explain the variation in total costs and in unit costs over time.

A. There is an increase in the overall unit costs during the bridge period and test year. This increase is driven by a significant reduction, in 2027, in purchases of 2S 200-Amp Smart Meters. Since the 3G changeout was completed in 2023, smart meters have performed better, decreasing the number of failures and creating a surplus inventory of meters. To run down this surplus meter inventory, the Company has eliminated purchase of these meters in 2027, driving the unit cost of smart meters and total meters up as the units that are being purchased are higher priced polyphase meters. The Company will evaluate

inventory levels and forecasts to resume purchase of the 2S 200 Amp meters in the second half of 2028 and beyond.

The overall variation in the unit cost of meters is also related to variation in the mix both in quantity and type of devices, as shown in Figure 67.

FIGURE 67
LVD METERING UNITS



	2023	2024	2025	2026	2027	2028
Smart Meters	97,784	64,749	49,912	35,376	5,136	25,896
3G/4G Replacements	44,760	0	0	0	0	0
Legacy Meters	240	420	600	992	992	992
Metering Transformers	5,090	5,985	8,632	3,855	3,855	3,855

For 2024, the unit costs were lower due to the mix of transformers purchased, with an increase in the number of smaller, less expensive current transformers. In 2021 and 2023, legacy meter unit costs were lower due to the quantity and mix of meters purchased. In 2021 and 2023, the only legacy meters purchased were 2S 200 Amp residential meters. For the other years, including the forecast for the bridge period and test year, there are higher quantities of polyphase meters included that are read via the Company's MV90 system. They are categorized as Legacy meters as they were not part of the Smart Energy

Deployment project. These meters are installed on large C&I electric customer locations. Smart meter unit costs were lower in 2021 due to lower numbers of polyphase meters purchased, then increased in 2022 and 2023 due to the purchase of more polyphase meters. Smart meter pricing is contractually fixed until 2032.

Q. Why is the Company continuing to purchase any legacy meters after the end of the implementation of smart meters?

A. The legacy meters in the Company's purchase plan primarily support operation of MV90 meters. MV90 meters essentially provide a type of automated meter reading for approximately 5,000 large C&I customers, by which meter interval data is collected either by an internet-over-IP or telephone communication with the meter. MV90 meters were determined to be out of scope for initial smart meter deployment for two main reasons. First, the billing tariffs for these customers are complex and would have required extensive hours of programming; since MV90 was already functional, the Company kept these meters out of scope for initial smart meter deployment. Second, some of these MV90 meters have a pulse output to provide real time data to customers and at the time of smart meter implementation through the present time, the meter vendor did not offer a smart meter option with pulse output, so the use of MV90 legacy meters was still required. Legacy meters, in very small numbers, are also purchased to support metering installations for customers who opt-out of the smart meter program.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spending per project for this subprogram. There is a wide variance among different meter types ranging from $125 per meter to as

high as $6,000 per meter. There is also a wide variance among metering transformers and meter sockets. Metering transformers range from $60 per unit to $2,500 per unit and meter sockets range from $26 per unit to $911 per unit. When projecting annual spend in this subprogram, the Company does use historical usage across meter types over the last three years as the basis for future purchase plan quantities. In addition, the plan considers major known projects that will require metering and associated devices in establishing the purchasing plan by device type. This establishes the meter mix and subsequent unit price submitted in the rate case. As the actual year progresses, the mix of meters will change based on the actual work mix requiring meters and associated devices that will impact the unit prices from year to year.

LVD Transformers

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Transformers subprogram.

A. The LVD Transformers subprogram supplies the distribution transformers that provide the means to supply electricity to customers at an acceptable voltage, with the number of transformers needed driven primarily by activity in the LVD Lines New Business subprogram. Historically, LVD transformer purchases have been allocated across the New Business, Demand Failures, and Capacity programs for accounting reasons, but because these separate LVD transformer subprograms operated through a single purchase plan for distribution transformers, the Company is combining all LVD transformer purchases into a single subprogram under New Business for rate case purposes.

Q. How are the projected LVD Transformers expenditures aligned with the Reliability Roadmap?

A. As noted in the Reliability Roadmap, supply chain issues led to an increase in the unit costs of transformers, and while the Company has worked to diversify its supply chain, it must continue to purchase transformers to meet customer demand.

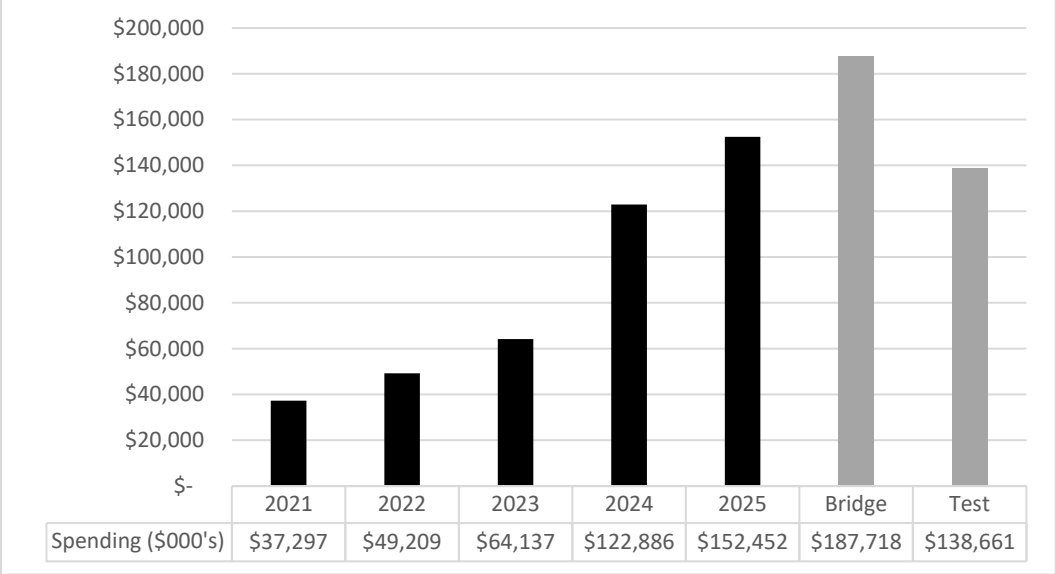
Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers subprograms?

A. The installation of distribution transformers is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, the benefits of which were described earlier in my direct testimony. The benefits of specialized transformers like voltage regulators allow the Company to condition the voltage on distribution circuits to ensure service to customers is delivered within the voltage range specified in Company tariffs.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD transformers subprograms?

A. The Company is projecting LVD Transformers capital expenditures of $187,718,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 3, column (k), and $138,661,000 in the test year, as shown in Exhibit A-87 (EMD-3), line 3, column (l). The Company's historical actual spending in the LVD Transformers subprograms, along with the bridge period and test year forecasts, are shown below in Figure 68. After increasing expenditures in the earlier part of the decade, the Company's projected test year expenditures are lower than actual expenditures in 2025.

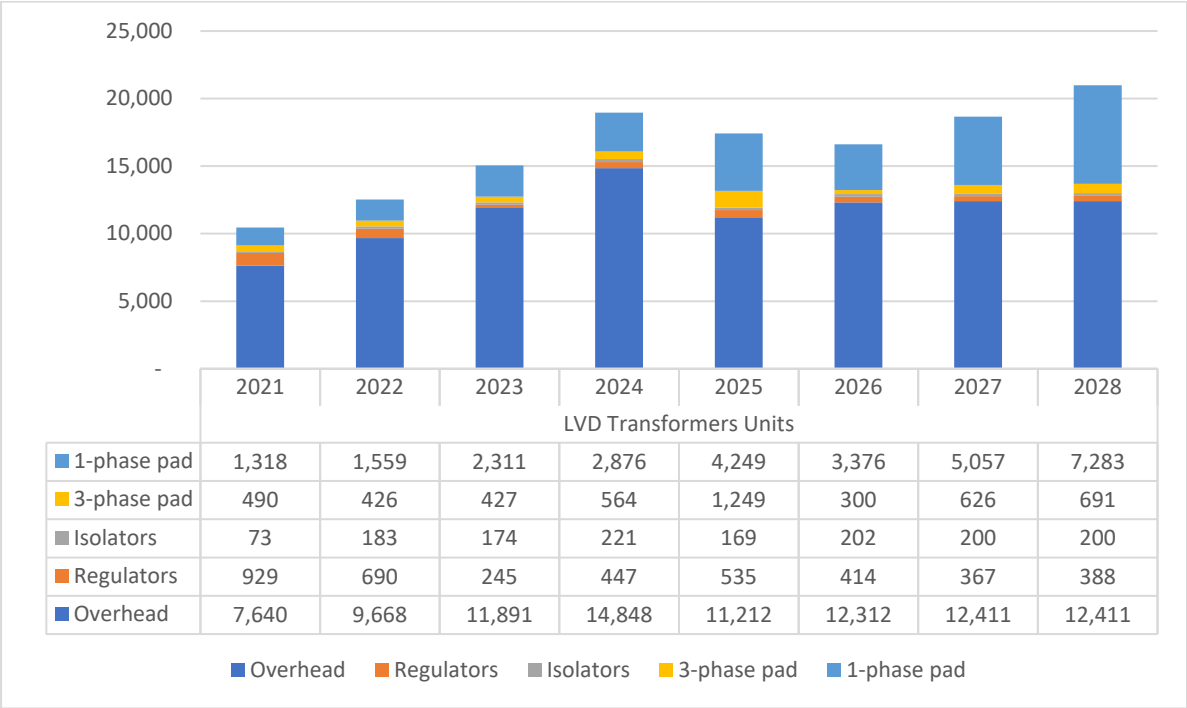
FIGURE 68
LVD TRANSFORMERS SUBPROGRAMS TOTAL EXPENDITURES



Q. How did the Company develop its projected expenditures in the LVD Transformer subprograms?

A. The Company develops its distribution transformer purchase plan by estimating the total number of transformers needed, based on historical actual data, with potential fluctuation in individual years based on lines projects in the Company's reactive spending programs. The historical number of transformer purchases (for 2020 through 2025) is shown in Figure 69 below, followed by projected purchases in future years (for 2026 through 2028). In 2026 and beyond, the Company is planning for a continued significant increase in purchases of padmount transformers tied to increased undergrounding work for both new service connections and primary and secondary circuits; for general new business work; and for the need to support customers adopting EVs.

FIGURE 69
LVD TRANSFORMERS UNITS

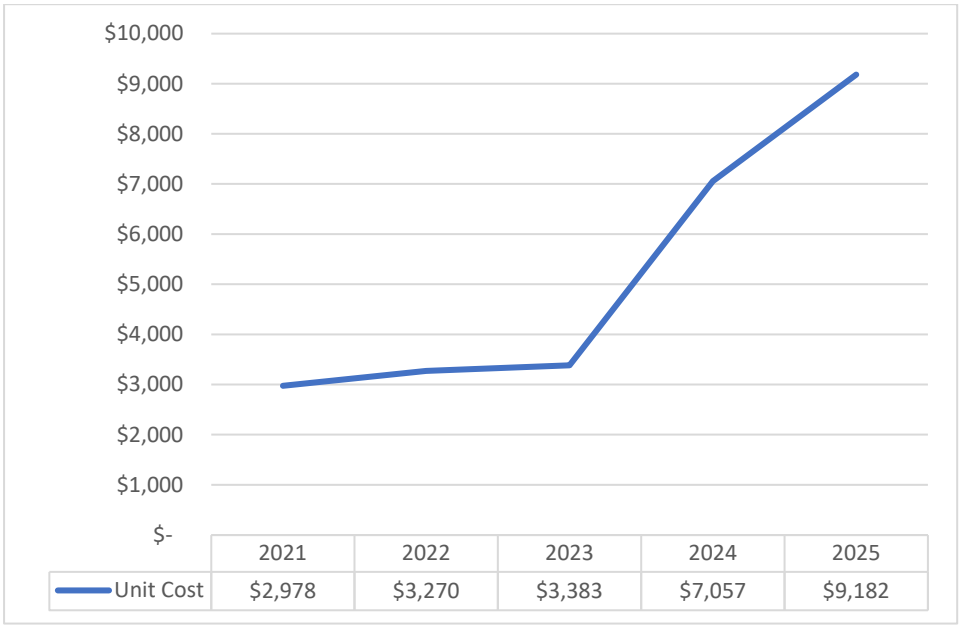


LVD Transformers Units	2021	2022	2023	2024	2025	2026	2027	2028
1-phase pad	1,318	1,559	2,311	2,876	4,249	3,376	5,057	7,283
3-phase pad	490	426	427	564	1,249	300	626	691
Isolators	73	183	174	221	169	202	200	200
Regulators	929	690	245	447	535	414	367	388
Overhead	7,640	9,668	11,891	14,848	11,212	12,312	12,411	12,411

Q. What are the historical unit costs for the LVD transformers subprogram?

A. The historical unit cost of transformers is provided in Figure 70.

FIGURE 70
LVD TRANSFORMERS UNIT COSTS



	2021	2022	2023	2024	2025
Unit Cost	$2,978	$3,270	$3,383	$7,057	$9,182

Q. Please explain any variation in unit costs over time.

A. Overall unit costs for transformers have increased over the historical period, partially due to inflation. The transformer sector, as an industry, has experienced at least a 6% increase year-over-year in cost, and this increase is projected to continue at 5% in the future. Additionally, the Company maintains an inventory of more than 400 transformer types, and unit costs each year can vary depending on the mix of transformer types the Company purchases each year, as discussed further below. For 2021 and 2022, raw material shortages and labor issues caused domestic supply to shrink and the cost of transformers in each year to increase by 30% over the previous five-year historical averages. In total, the cost of padmount transformers increased by 50% from 2022 and 2024 due to demand/supply imbalances.

As a result of these supply challenges, the Company initiated a supply base diversification strategy, including new overseas manufacturers. This supply base diversification was necessary to mitigate lead-time increases and capacity risks with domestic manufacturers. Transportation and higher manufacturing costs from these suppliers led to higher unit costs in 2024 (transportation costs are higher for products that must be shipped from other countries). In short, the Company's supply diversification strategy for transformers has better ensured that the Company can meet customer demand, but did involve increased costs.

In addition, purchases of lower-priced units like overhead transformers has slowed while purchases of larger three-phase and single-phase padmount transformers has increased in this same period. Since 2024, the Company has accelerated its procurement of three-phase transformers (226% more than 2024), padmount transformers (40% more), and

voltage regulators (33% more). The increase is driven by anticipated increased residential load such as EVs, heat pumps, and instantaneous water heaters, as well as the Company's planned increase in undergrounding work. Increased regulator procurement is attributable to expansion of ATRs and CVR programs.

Q. Does an average unit cost accurately reflect the expected spending per transformer for this subprogram?

A. Unit cost is not an ideal measure of spending to predict the cost of a single transformer in this subprogram, as it includes a wide range of transformer types which are not directly comparable. Transformers can cost as little as $500 but also as much as $25,000 or more depending on application. Ultimately, the overall sub-program unit cost is heavily dependent on the mix of transformer types purchased in a given year. The actual 2025 unit costs for each class of transformer are shown in Figure 71 below.

FIGURE 71
2025 ACTUAL TRANSFORMER UNIT COSTS

Transformer Class	2025 Unit Cost
1-Phase Padmount	$5,303
3-Phase Padmount	$27,803
Isolator	$13,199
Regulator	$28,617
Overhead	$2,768

The transformer purchase plan includes traditional transformers that provide service to customers as well as specialized transformers like voltage regulators that respond to changes in voltage on the primary system and adjust to ensure adequate voltage. As noted above, demand for larger, higher cost padmount transformers has increased while overhead units have leveled off.

Electric Other Program

Q. What is included in the Electric Other Program?

A. Company witness Duke introduces the Electric Other Program in her direct testimony. This testimony will address the Tools sub-program. The Electric Other Program also includes Computers and Equipment; System Control Projects; and Grid Technologies, which are addressed by Company witness LaFrance in his direct testimony.

Tools

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Tools sub-program.

A. This sub-program covers the purchase of new and replacement tools for utility workers that are worn, broken, outdated, and/or unrepairable when the tools are priced over $1,000 per item. Some examples of these tools covered in this sub-program include:

- Cordless cutting, crimping, and hammering/breaking tools
- Concrete cutting/boring tools with silica mitigation systems
- Remote cutting and spiking tools
- Calibrated metering tools
- Customer service integrity meters
- Substation Testing instruments
- System/service diagnostic or locating equipment
- Line segmenting (load drop/load pickup) devices
- System reconductoring accessories
- Specialty rigging, work lighting, pumping or “bridging” and “matting” equipment

Since 2016, this sub-program included outfitting new Company trucks, including service bucket trucks, two-person buckets, and digger derricks with standard packages of essential tools to ensure that crews go into the field with appropriate equipment, referred to as "truck tool kits." The funds for these truck tool kits are transferred from the Tools sub-group to Fleet, allowing for the purchase of the truck tool kits to coordinate with the purchase/delivery of each new truck. The purchase plan for these truck tool kits is based on the Company's fleet acquisition and deployment plan. As the Company is planning to expand its Operations workforce, the Company will need to purchase additional capital tools (besides truck tool kits).

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Tools sub-program?

A. A properly outfitted truck and crew enable a safer, faster response to outages, safe and efficient installation of new services, and more productive completion of projects with less waste and lower unit costs. Company crews require appropriate tools and equipment when in the field, both to ensure their own safety and the safety of the public, and to be able to complete their work in an expeditious manner to complete maintenance and construction work and reduce outage times. Spending in this sub-program ensures that tools are replaced in a timely manner before the expiration of the tool's life, while ensuring that Company trucks are always stocked with appropriate tools for workers to safely complete their work.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Tools sub-program?

A. The Company is projecting capital expenditures of $9,652,000 in the bridge period, as shown in Exhibit A-87 (EMD-3), line 40, column (k), and $8,277,000 in the projected test year, as shown in Exhibit A-87 (EMD-3), line 40, column (l).

Q. What is the basis for the Company's projected spending level in this sub-program?

A. The projected spending level in this sub-program is based on the needs of the Company for capital tools and truck tool kits. The cost of capital tools is based on prices quoted from vendors for the specific models. Prices for each tool make and model can vary annually due to inflation and other supply chain constraints.

The tool purchases in the bridge period will support all electric operations, including the new Underground Construction group that focuses on installing new customer underground infrastructure, including primary cable and transformers. Figure 72 outlines the Company's bridge period investment categories and units in the Tools sub-program.

FIGURE 72
BRIDGE PERIOD INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (54 units)	$3,480,000
Other Capital Tool Purchases	
General Capital Tools	*$2,952,000*
Reconducting Trailer Equipment	*$900,000*
Employee Fall Restraint	*$100,000*
Battery Hi-Pot Testers	*$120,000*
UG Primary Wire Stripper	*$200,000*
HVD Test Equipment	*$500,000*
Meter Service CT Lifters (ergonomics)	*$150,000*
Thumpers	*$250,000*
Shoring Boxes	*$250,000*
Underground Department tools	*$750,000*
Total	**$9,652,000**

In the test year, the Company will continue with its process of purchasing truck tool kits for new Company trucks, with 50 truck tool kits in the test year, aligned with the Company's fleet acquisition and deployment plan, necessary to support the Company's expanding workforce to complete the increased workload necessary to address new business requests, system capacity, and system reliability work. The increase in the Capital Tool Purchases category reflects the increased need to support additional work and work groups focused on HVD system reliability. Due to the nature of this work, the tools purchased for any new or additional group have a specific purpose and voltage rating, thus making the investment more focused on the work practices. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 73 below.

FIGURE 73
TEST YEAR TOOLS INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (50 units)	$3,150,000
Other Capital Tool Purchases	
General Capital Tools	$2,927,000
Battery Hi Pot Tool for LVD	$400,000
HVD Test Equipment Upgrades	$500,000
Remote Operated Equipment Lubrication Applicator	$200,000
Light Weight Ergonomic Service Savers	$200,000
Underground Work Group Tool Support	$500,000
Fall Restraint	$100,000
Hydraulic Tool Replacements	$250,000
Total	**$8,277,000**

Q. Please explain the coordination between Fleet and Electric Operations to procure Truck Tool Kits.

A. Starting in 2016, the Electric Operations Tools sub-program has set aside budgeted dollars to purchase truck tool kits for the bucket and digger trucks that Fleet plans to purchase. The Tools sub-program then transfers the allocated dollars to Fleet, creating a packaged purchase with Fleet's selected vendor. This is done because the tools included in these tool packages are considered standard equipment for the vehicles and ensure that crews go into the field with the necessary resources. In 2022, however, no money was transferred for the purpose of new truck tool kits. Due to Fleet-related disallowances in the Commission's Order in Case No. U-20963, the Company wrote off or sold a number of vehicles. Truck tool kits can only be accounted for in Fleet if there are associated vehicles; the result of this was that no transfers were made in 2022.

Historical data in Figure 74 below shows the overall annual truck tool kit dollars that were earmarked by the Electric Operations Tool department, then transferred to Fleet within the truck purchase.

FIGURE 74
TRUCK TOOL PACKAGES BY YEAR

	2021	2022	2023	2024	2025	Bridge Period	Test Year
Number of truck tool packages	18	0	16	24	67	54	50
Truck tool package spending	$5,885,000	$0	$560,000	$727,000	$2,670,176	$3,480,000	$3,150,000

Q. What has been the historical actual spending in the Tools sub-program for the past five calendar years?

A. The historical actual spending in the Tools sub-program for the past five calendar years is shown in Figure 75 below. This level of spending is what the Company requires to replace capital tools in lifecycle, create consistency (for training and in-field use) between Electric Operations work groups, provide Fall Restraint tools for Apprentices and new hire Journey-workers based on the total of individuals hired, and support the purchase of truck tool packages to equip the Company's growing workforce.

FIGURE 75
TOOLS HISTORIC EXPENDITURES

2021	2022	2023	2024	2025	5-Year Average
$5,214,000	$5,257,000	$4,560,000	$7,773,000	$5,790,827	5,718,965

Q. Please explain year-over-year variation in spending in this sub-program.

A. Spending in this sub-program has been increasing for three reasons. First, the Company has been purchasing truck tool packages for LVD line worker vehicles since 2016, and in 2021 began purchasing them for other groups in the Electric Operations department as well. Second, tool prices have increased, and the Company has invested in newer types of tools to improve safety. As more tools reach the end of their useful life and must be replaced, the Company's spending in this sub-program has increased to replace older tools with safer and more advanced ones. In particular, the Company has invested in more ergonomic tools, such as battery-operated cutters, drills, impact wrenches, and crimpers, to reduce the frequency and severity of injuries and achieve occupational health goals. Third, the Company has created a new workgroup to support Underground construction. This workgroup has driven an increase in truck tool kit purchases and purchases of tools used in underground utility work.

SUMMARY

Q. Please provide a brief summary of your testimony and the intent of investing in LVD capital subprograms to support the Company's electric distribution system.

A. The testimony provided an overview of the LVD system and associated capital investments to improve reliability and resiliency of the system while serving new customers to support economic development in the state of Michigan. The testimony provided detail of each LVD capital investment program and the basis of planned investments and benefits. The LVD capital investments outlined in my testimony are identified and planned to support the overall objectives and strategy outlined in the Company's Reliability Roadmap and those introduced by Company witness Duke.

Q. Please summarize the LVD capital expenditure plan in this filing.

A. The LVD capital expenditure plan outlined in this testimony is summarized in Figure 76 below. Dollars shown are in thousands.

FIGURE 76
LVD CAPITAL EXPENDITURE SUMMARY ($000)

	2025 Actuals	Bridge Period	Test Year
LVD Capital	$894,515	$1,302,901	$1,017,412

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

HANNAH L. PATTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Hannah L. Patton, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rates Analyst in the Revenue Requirements and Analysis Section of the Rates and Regulation Department.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics & Management from Albion College in 2009. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your professional experience.

A. From 2007 to 2011, I practiced public accounting with the accounting firm Rehmann Robson with a focus on performing financial statement, internal control and compliance audits for companies in various industries.

I began working for the Company in January 2012 in the Electric Revenue and Fuel Cost Accounting section of the General Accounting Department as a General Accounting Analyst I. I was promoted to General Accounting Analyst II in 2013, a Senior Accounting Analyst I in 2015, a Senior Accounting Analyst II in 2017, and a Senior Accounting Analyst III in 2020. In 2022, I was promoted to Manager of Revenue and Fuel Cost Accounting with responsibility for overseeing accounting for electric generation and power supply expenses, the cost of gas, and the accounting for the Company's mandatory and voluntary Renewable Energy programs, as well as the analysis of electric and gas revenues, costs, and related over- or under-recoveries.

In February 2025, I transitioned to my current position.

Q. What are your responsibilities as a Principal Rates Analyst at Consumers Energy?

A. I am responsible for conducting analyses to determine the Company's revenue requirements and for preparing testimony and supporting exhibits for regulatory filings submitted to the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously filed testimony with the MPSC?

A. Yes, I have sponsored testimony in the following cases:

- MPSC Case No. U-17631, the Company's 2013 Renewable Energy ("RE") Reconciliation Case;
- MPSC Case No. U-17803, the Company's 2014 RE Reconciliation Case;
- MPSC Case No. U-18081, the Company's 2015 RE Reconciliation Case;
- MPSC Case No. U-18241, the Company's 2016 RE Reconciliation Case;
- MPSC Case No. U-17918-R, the Company's 2016 Power Supply Cost Recovery ("PSCR") Reconciliation Case;
- MPSC Case No. U-20068, the Company's 2017 PSCR Reconciliation Case;
- MPSC Case No. U-20202, the Company's 2018 PSCR Reconciliation Case;
- MPSC Case No. U-20220, the Company's 2019 PSCR Reconciliation Case;
- MPSC Case No. U-20802, the Company's 2021 PSCR Plan Case;
- MPSC Case No. U-20542, the Company's Gas Cost Recovery ("GCR") Reconciliation Case;
- MPSC Case No. U-20803, the Company's 2021 PSCR Reconciliation Case;
- MPSC Case No. U-21141, Carbon Offset Program;
- MPSC Case No. U-21148, Gas Rate Case;
- MPSC Case No. U-20815, the Company's GCR Reconciliation Case;
- MPSC Case No. U-21049, the Company's 2022 PSCR Reconciliation Case;

- MPSC Case No. U-21063, the Company's GCR Reconciliation Case;
- MPSC Case No. U-21352, the Company's 2022 RE Reconciliation Case;
- MPSC Case No. U-21258, the Company's 2023 PSCR Reconciliation Case;
- MPSC Case No. U-21270, the Company's GCR Reconciliation Case;
- MPSC Case No. U-21549, the Company's 2023 RE Reconciliation Case;
- MPSC Case No. U-21592, the Company's 2025 PSCR Plan Case; and
- MPSC Case No. U-21873, the Company's 2026 PSCR Plan Case.

Q. What is the purpose of your direct testimony in this proceeding?

A. In my direct testimony, I will cover the following topics: (i) the Company's revenue deficiency/(sufficiency) calculation for the historical year; (ii) the Company's revenue deficiency calculation for the projected test year; (iii) requests related to distribution capital deferrals; and (iv) the projected test year revenue requirement for the Demand Response ("DR") Programs. In addition, I will address the regulatory assets and liabilities included for recovery in this case related to the Company's Low Voltage Distribution ("LVD") Forestry Ramp-Up program, the SAP S/4 HANA Implementation Project ("SAP S/4HANA Project"), the March/April 2025 storm deferral, and the Itron refund as described in Case No. U-21502.

Q. How is your direct testimony organized?

A. My direct testimony is organized in sections consistent with the topics I will be covering:

SECTION I: HISTORICAL YEAR

SECTION II: PROJECTED TEST YEAR

SECTION III: REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENT

SECTION IV: DISTRIBUTION DEFERRAL

SECTION V: DEMAND RESPONSE

Q. How does the Company present the historical and projected revenue deficiency calculations?

A. The Company presents the historical and projected revenue deficiency calculations in compliance with the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Please describe the revenue requirements determination.

A. My direct testimony presents the revenue sufficiency for the actual historical period. Additionally, my direct testimony presents and explains how the revenue deficiency for the future projected test year was developed. I will also reconcile the historical and projected test year periods. Through this filing, the Company demonstrates that it requires a rate increase to earn a just and reasonable return.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. The historical test year exhibits are identified in Section I of my direct testimony. The projected test year exhibits are identified in Section II of my direct testimony. In addition, I am sponsoring the following exhibits:

Exhibit A-180 (HLP-58)	Regulatory Asset Summary of Forestry Ramp-up;
Exhibit A-181 (HLP-59)	Demand Response Revenue Requirement;
Exhibit A-182 (HLP-60)	Distribution Deferral for the projected test year ending February 28, 2026;
Exhibit A-183 (HLP-61)	Distribution Deferral for the projected test year ending April 30, 2027;
Exhibit A-184 (HLP-62)	Regulatory Asset and Amortization of the March/April 2025 Storm Deferral; and
Exhibit A-185 (HLP-63)	Regulatory Asset and Amortization Expense of Case No. U-21502 (Itron Refund).

Q. Were the exhibits presented in your direct testimony prepared by you or under your direction and supervision?

A. Yes.

I. HISTORICAL YEAR

Q. What is the actual historical year used in the exhibits and supporting testimony?

A. The Company selected the 2025 calendar year as the historical year.

Q. Please identify the exhibits that you are sponsoring associated with the historical year.

A. The following exhibits are being submitted to satisfy the historical test year requirements:

Exhibit A-1 (HLP-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2025;
Exhibit A-1 (HLP-2)	Schedule A-2	Historical Financial Metrics – Electric Results Only;
Exhibit A-2 (HLP-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2025;
Exhibit A-2 (HLP-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2025;
Exhibit A-2 (HLP-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2025;
Exhibit A-2 (HLP-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2025;
Exhibit A-2 (HLP-7)	Schedule B-5	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2025;
Exhibit A-2 (HLP-8)	Schedule B-6	Point-In-Time Balance Sheet for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2025;

Exhibit A-3 (HLP-10)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-11)	Schedule C-3	Operating Revenue for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-12)	Schedule C-4	Cost of Fuel and Purchased Power for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-13)	Schedule C-5	Operation and Maintenance Expenses for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-14)	Schedule C-5.1	Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-15)	Schedule C-6	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-16)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-17)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-18)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-19)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-20)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2025;
Exhibit A-3 (HLP-21)	Schedule C-12	Income Tax Effect of Interest for the Historical Year Ended December 31, 2025;

Exhibit A-3 (HLP-22)	Schedule C-13	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2025;
Exhibit A-4 (HLP-23)	Schedule D-1	Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2025;
Exhibit A-4 (HLP-24)	Schedule D-2	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2025;
Exhibit A-4 (HLP-25)	Schedule D-3	Cost of Short-Term Debt for the Historical Year Ended December 31, 2025;
Exhibit A-4 (HLP-26)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2025; and
Exhibit A-4 (HLP-27)	Schedule D-5	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2025.

Q. Please discuss the organization and format of the historical period exhibits.

A. The organization and format of the historical period exhibits are specified by the MPSC's filing requirements. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), adjusted Net Operating Income ("NOI") (Schedule C), and rate of return (Schedule D).

Q. Who is sponsoring the historical year Schedule E exhibits?

A. The historical year Schedule E exhibits are sponsored by Company witness Eugene M. Breuring.

Q. Please describe the Schedule A exhibits for the historical period.

A. Exhibit A-1 (HLP-1), Schedule A-1, is the computation of the electric revenue deficiency/sufficiency for the year ended December 31, 2025. Exhibit A-1 (HLP-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on both a financial

basis (pages 1 through 3) and a ratemaking basis (pages 4 through 6) for the years 2021 through 2025. Pages 1 and 4 calculate an electric earned rate of return on common equity for each of these years. The $6.1 million electric revenue sufficiency is shown on Exhibit A-1 (HLP-1), Schedule A-1, line 8. Schedule A-1 is developed from financial data presented in Schedules B, C, and D described below.

Q. Please describe the Schedule B exhibits for the historical period.

A. Exhibit A-2 (HLP-3), Schedule B-1, presents the calculation of average electric rate base for the year ended December 31, 2025 in the amount of $15 billion as shown on line 7, which is carried forward to Exhibit A-1 (HLP-1), Schedule A-1, line 1. Exhibit A-2 (HLP-4), Schedule B-2, through Exhibit A-2 (HLP-8), Schedule B-6, support the development of the various components of average rate base including net utility plant and working capital.

Q. Please describe the Schedule C exhibits for the historical period.

A. Exhibit A-3 (HLP-9), Schedule C-1, presents the calculation of adjusted NOI for the year ended December 31, 2025 in the amount of $893.1 million, as shown on line 32, which is carried forward to Exhibit A-1 (HLP-1), Schedule A-1, line 2. Exhibit A-3 (HLP-10), Schedule C-2, through Exhibit A-3 (HLP-22), Schedule C-13, support the development of the various components of adjusted NOI. The Schedule C data for the historical period is generally sourced to the Company's 2025 Form P-521 Annual Report to the MPSC.

Q. Please describe the Schedule D exhibits for the historical period.

A. Exhibit A-4 (HLP-23), Schedule D-1, presents the overall rate of return summary for the year ended December 31, 2025. The weighted cost of capital of 5.91% is shown on line 14, column (h), and is carried forward to Exhibit A-1 (HLP-1), Schedule A-1, line 4. Exhibit

A-4 (HLP-24), Schedule D-2, through Exhibit A-4 (HLP-27), Schedule D-5, support the development of various components of the overall rate of return for the historical period including: (i) debt; (ii) preferred stock; (iii) common equity; and (iv) other sources of financing.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?

A. No. I have calculated a historical year revenue sufficiency for the 12-month period ended December 31, 2025, of $6.1 million, which is presented on Exhibit A-1 (HLP-1), Schedule A-1, as follows:

Jurisdictional	***($ In Thousands)***
Rate Base	$15,041,063
Adjusted NOI	$ 893,051
Overall Rate of Return	5.94%
Required Rate of Return	5.91%
Income Required	$ 888,507
Income Deficiency (Sufficiency)	(4,544)
Revenue Multiplier	1.3381
Revenue Deficiency (Sufficiency)	$ (6,080)

Q. Do the above results include typical ratemaking adjustments such as weather; unusual, one-time, or out-of-period items; and regulatory disallowances?

A. Yes. The historical year presentation begins with the Company's booked results, then ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (HLP-9), Schedule C-1. I will describe the adjustments and

normalizations in the second part of my direct testimony, which covers the projected test year.

II. PROJECTED TEST YEAR

Q. What projected test year has the Company used in this case?

A. The Company selected the 12 months ending April 30, 2028 as the projected test year in this proceeding.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's filing requirements related to the projected test year.

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

Exhibit A-11 (HLP-28)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-11 (HLP-29)	Schedule A-2	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-11 (HLP-30)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-12 (HLP-31)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-12 (HLP-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-12 (HLP-33)	Schedule B-3	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending April 30, 2028;

Exhibit A-12 (HLP-34)	Schedule B-4	Working Capital Summary for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-12 (HLP-35)	Schedule B-5	Capital Expenditures Summary for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-36)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-37)	Schedule C-1.1	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-38)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-39)	Schedule C-3	Operating Revenues for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-40)	Schedule C-4	Cost of Fuel and Purchased Power for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-41)	Schedule C-5	Operating and Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-42)	Schedule C-5.1	Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-43)	Schedule C-6	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending April 30, 2028;

Exhibit A-13 (HLP-44)	Schedule C-7	General Taxes for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-45)	Schedule C-8	Federal Income Taxes for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-46)	Schedule C-9	State Income Taxes for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-47)	Schedule C-10	Other (or Local) Taxes for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-48)	Schedule C-11	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-49)	Schedule C-12	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-13 (HLP-50)	Schedule C-13	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-173 (HLP-51)		Regulatory Asset and Amortization Expense of the PowerMIDrive and PowerMIFleet for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-174 (HLP-52)		Regulatory Asset and Amortization of Karn and Campbell Plant Retention and Separation Costs for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-175 (HLP-53)		Regulatory Asset and Amortization Expense of the Net Book Value of Campbell Plant 1, 2, and 3 for the Projected 12-Month Period Ending April 30, 2028;

Exhibit A-176 (HLP-54)	Regulatory Asset and Amortization Expense of Karn and Campbell Decommissioning Costs for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-177 (HLP-55)	Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2028;
Exhibit A-178 (HLP-56)	Regulatory Asset and Amortization Expense of the Pension and OPEB Volatility Mechanism, for the Projected 12-Month Period Ending April 30, 2028; and
Exhibit A-179 (HLP-57)	Campbell Regulatory Asset – Return On for the Projected 12-Month Period Ending April 30, 2028.

Q. Please discuss the organization and format of the projected test year exhibits.

A. The projected test year exhibits are organized and formatted in a similar fashion to the historical period exhibits. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), and adjusted NOI (Schedule C). Company witness Marc R. Bleckman is sponsoring schedules that address rate of return (Schedule D). Company witness Breuring is sponsoring sales, load, and customer data (Schedule E) exhibits. Company witness Emily A. Davis is sponsoring the cost-of-service study. Company witness Michael C. Grondin is sponsoring present and proposed revenue. Company witness Brittani A. Gray is sponsoring the proposed tariff sheet (Schedule F) exhibits.

Q. Please summarize the key findings for the projected test year exhibits.

A. Exhibit A-11 (HLP-28), Schedule A-1, presents the projected revenue deficiency for the 12-month period ended April 30, 2028, as follows:

	($ In Thousands)
Rate Base	$17,022,569
Adjusted NOI	834,710
Overall Rate of Return	4.90%
Required Rate of Return	6.59%
Income Required	$ 1,122,345
Income Deficiency (Sufficiency)	287,635
Revenue Multiplier	1.3381
Revenue Deficiency (Sufficiency)	$ 384,878
Return On – Campbell Regulatory Asset	70,954
Total Revenue Deficiency (Sufficiency)	$ 455,832

Q. Why is the Company no longer presenting a jurisdictional electric revenue deficiency for the projected test year?

A. The Company no longer presents a separate jurisdictional electric revenue deficiency for the projected test year because the total Company revenue deficiency is fully jurisdictional. At present, there is only one contract classified as non-jurisdictional. The contract utilizes the General Meter Lighting tariff rate for all charges on the bill, except for a two-mil discount on the energy charge. While this contract remains in place, the Company has included its projected revenues and the value of the discount as miscellaneous revenues in the instant case. Accordingly, the Company has streamlined its presentation by reporting a single total electric revenue deficiency (or sufficiency) for both the historical and projected test years.

Q. What inflation factors is the Company using in its presentation?

A. The Company is using inflation factors of 2.90% for 2026, 2.50% for 2027, and 2.20% for 2028,1F[1] as forecasted by S&P Global Market Intelligence and reported in the November 2025 edition of its publication *U.S. Economic Outlook*. S&P Global Market Intelligence is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. Has the Company provided a summary of where these inflation factors have been used in the case?

A. Yes. Exhibit A-13 (HLP-42), Schedule C-5.1, provides a summary of the inflation included in Other Operating and Maintenance ("O&M") Expenses in the case.

Q. How has Consumers Energy addressed the MPSC's filing requirement to reconcile the projected test year to the most recent calendar year?

A. The following is a list of exhibits that reconcile the projected test year to the historical:

i. Exhibit A-11 (HLP-30), Schedule A-3;

ii. Exhibit A-12 (HLP-34), Schedule B-4;

iii. Exhibit A-13 (HLP-37), Schedule C-1.1; and

iv. Exhibit A-13 (HLP-41), Schedule C-5.

Q. Please explain Exhibit A-11 (HLP-29), Schedule A-2.

A. This exhibit provides the financial metrics and statistics for the projected test year as required by the MPSC's filing requirements. Column (b) shows the metrics assuming no rate relief is granted. Column (c) shows the metrics assuming the Company's full-rate relief request is granted.

[1] 0.7% for 4-month proration

Q. Please explain Exhibit A-11 (HLP-30), Schedule A-3.

A. This exhibit presents the projected test year revenue deficiency of $455.8 million (line 11, column (f)). Column (d) of the exhibit presents pertinent rate base and rate of return amounts for the historical period. Column (e) shows the changes resulting from adjustments supported by the various Company witnesses that were made in developing the projected test year revenue deficiency. Column (f) then displays the projected test year rate base, income requirement, and revenue requirement.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HLP-30), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (HLP-30), Schedule A-3, shows that rate base increases by $2.0 billion (line 3) and the rate of return increases from 5.91% to 6.59% (line 4). In addition, the adjusted NOI (line 6) decreases by $58.3 million when moving from the historical year to the projected test year.

Q. Please describe Exhibit A-12 (HLP-31), Schedule B-1.

A. Exhibit A-12 (HLP-31), Schedule B-1, is a summary presentation of the projected test year average rate base of $17.0 billion as shown on line 7.

Q. Please describe Exhibit A-12 (HLP-32), Schedule B-2.

A. Exhibit A-12 (HLP-32), Schedule B-2, presents the total utility plant for the projected test year. The total on line 24 is carried forward to line 1 on Exhibit A-12 (HLP-31), Schedule B-1.

Q. Please describe how the projected test year average plant and related amounts were developed.

A. Utility plant and reserve balances for the projected test year were developed by calculating a 13-month average of the balances as of April 30, 2027 through April 30, 2028. Actual calendar year 2025 balances for construction work-in-progress ("CWIP"), gross plant, and accumulated depreciation were used as the starting point. Projected capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for the calendar year 2026, calendar year 2027, and the first four months of 2028; followed by adjustments for projected retirements, depreciation expense, cost of removal, and the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Did you make any adjustments to the December 2025 balances used as the starting point?

A. Yes. I made several adjustments to the December 2025 balances. First, I removed the historical balances associated with J.H. Campbell ("Campbell") Units 1, 2, and 3 to reflect their treatment as a regulatory asset, as explained in Section III of my direct testimony.

Second, I removed the impacts of calendar year 2025 expenditures related to the Company's River Hydro investments from historical plant in service, construction work in progress, and accumulated depreciation. As explained by Company witness Heidi J. Myers, the Company is proposing to extend the hydro revenue requirement deferral approved in Case No. U-21585 and Case No. U-21870. As this deferral began in 2024, the removal of the 2025 hydro expenditures is required.

Finally, I removed the historical plant in service and accumulated depreciation amounts (i.e., the net book value) associated with Fleet Bucket Truck Remediation involving 88 bucket trucks, as described by Company witness Joshua J. Judy. The Company has removed the historical net book value of these trucks because it anticipates they will be disposed of prior to the start of the test year. The Company further proposes that any net gain from the disposition of these trucks, after considering disposal or other related fees, be recorded as an offset (i.e., a reduction to rate base) against the cost of the new vehicles described by Company witness Judy.

Q. Please describe Exhibit A-12 (HLP-33), Schedule B-3.

A. Exhibit A-12 (HLP-33), Schedule B-3, presents the projected depreciation reserve for the projected test year by functional group. The total on line 17 is carried forward to line 2 on Exhibit A-12 (HLP-31), Schedule B-1. The increase in the projected accumulated depreciation provision for the projected test year incorporates depreciation expense calculated using book depreciation rates approved by the Commission in Case No. U-20849. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-20844.

Q. Please explain Exhibit A-12 (HLP-34), Schedule B-4.

A. Exhibit A-12 (HLP-34), Schedule B-4, develops the Company's proposed projected test year balance sheet working capital requirement. The starting point is the 13-month average historical December 2025 working capital shown in column (b). The December 2025 average balances are then adjusted to reflect changes to:

i. Pension and Other Post-Employment Benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob, and the regulatory asset and liability related to the volatility mechanism;

ii. Accrued tax balances;

iii. Prepaid cloud computing balances sponsored by Company witness Stacy H. Baker;

iv. Regulatory asset balances for PowerMIDrive and PowerMIFleet deferred costs;

v. Regulatory asset balances for D.E. Karn ("Karn") and Campbell retention costs, Campbell plant's net book value, and various coal plants' decommissioning and ash disposal costs;

vi. Cash balance sponsored by Company witness Bleckman;

vii. Deferred debits for a software implementation deferral sponsored by Company witness Baker; and

viii. Regulatory liability balance related to the Itron refund ordered by the Commission in Case No. U-21502.

Q. Why did the Company use the balance sheet approach in determining the working capital requirement?

A. Use of the balance sheet method was mandated by the Commission in Case No. U-7350. The Commission, in Case No. U-15895, also required that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (HLP-35), Schedule B-5.

A. Exhibit A-12 (HLP-35), Schedule B-5, provides a summary of capital spending as supported by various Company witnesses. This exhibit provides capital spending for the bridge year and projected test year as well as the projected and approved spending during the previous rate case test year in Case No. U-21870.

Q. Please describe Exhibit A-13 (HLP-36), Schedule C-1.

A. Exhibit A-13 (HLP-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $834.7 million as shown on line 19. Total operating revenues (line 4) are netted against total operating expenses (line 13) to arrive at net operating income on line 14. Further adjustments are made on lines 15, 17, and 18, which utilize normal ratemaking practices to arrive at adjusted NOI on line 19.

Q. Please explain Exhibit A-13 (HLP-37), Schedule C-1.1

A. Exhibit A-13 (HLP-37), Schedule C-1.1, presents the reconciliation of historical year NOI to projected test year NOI. The exhibit presents revenues in columns (c) through (e), expenses in columns (f) through (m), NOI in column (n), AFUDC in column (o), and adjusted NOI in column (p). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 14, and projected test year adjustments on lines 16 through 27. Total adjusted NOI for the projected test year is shown on line 28, column (p). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historical year NOI of $1,129.2 million on line 1, column (p), ties to the historic NOI on line 17 of Exhibit A-3 (HLP-9), Schedule C-1.

Q. Please explain the normalizing adjustments on Exhibit A-13 (HLP-37), Schedule C-1.1.

A. The adjustments located on lines 2 through 14 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical booked results such as: (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items; (iii) bringing certain revenues and expenses “above the line”;

(iv) adjusting historical revenues to reflect "normal" weather; and (v) performing related adjustments to income taxes. Additional adjustments include certain O&M expense normalizations to better align the historical year with expected expense amounts in the projected test year. These adjustments are supported by my exhibits and supporting workpapers, and from the exhibits of other Company witnesses.

The historical year adjusted NOI on Exhibit A-13 (HLP-37), Schedule C1.1, line 15, column (p), of $893.1 million, ties to historic NOI on line 32, column (c), of Exhibit A-3 (HLP-9), Schedule C-1.

Q. How were the projected test year adjustments on Exhibit A-13 (HLP-37), Schedule C-1.1, developed?

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year NOI. The adjustments on lines 16 through 27 are developed from my exhibits and supporting workpapers, and from the exhibits of other Company witnesses. The projected test year NOI on line 28 is the result of netting the projected test year adjustments on lines 16 through 27 against the historical year adjusted NOI on line 15. The projected test year adjusted NOI of $834.7 million on line 28, column (p), ties to the projected test year adjusted NOI on Exhibit A-13 (HLP-36), Schedule C-1, line 19.

Q. Please explain the test year adjustments made for the projected test year on Exhibit A-13 (HLP-37), Schedule C-1.1.

A. Lines 16 through 18 represent the changes in revenues when moving to the projected test year and are supported by Company witness Breuring. Line 19 represents an adjustment to the power supply costs shown on Exhibit A-13 (HLP-40), Schedule C-4, to align the

projected test year PSCR expense with the projected test year PSCR revenues proposed by Company witness Breuring.

Line 20 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Baker, Amy M. Conrad, Emily M. Duke, Matthew J. Foster, Alex M. Gast, Grob, Quentin A. Guinn, Sara E. Stewart, Mark E. Wittbrodt, and me. The adjustments are detailed on Exhibit A-13 (HLP-41), Schedule C-5 and Exhibit A-13 (HLP-42), Schedule C-5.1.

Line 21 represents the change in the book depreciation expense from the adjusted historical year to the projected test year. The Company used the Commission-approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense for the projected test year. The adjustment on line 21 increases depreciation expense from the historical period due to new capital investment.

Line 22 represents an adjustment to real and personal property taxes to the projected test year expense level as supported by Company witness Brian J. VanBlarcum and shown on Exhibit A-13 (HLP-44), Schedule C-7, line 1.

Line 23 represents the change in historical year payroll and other general taxes to the projected test year amount as shown on Exhibit A-13 (HLP-44), Schedule C-7, lines 6 and 15.

Line 24 represents city income tax adjustments to the projected test year level city income tax expense as shown on Exhibit A-13 (HLP-47), Schedule C-10, line 18.

Line 25 reflects the impact of Michigan Corporate Income Tax ("CIT") ("MCIT"). The projected test year MCIT expense is shown on Exhibit A-13 (HLP-46), Schedule C-9, line 20.

Line 26 represents the Federal Income Tax ("FIT") adjustments which result from the other changes in revenue and expense levels for the projected test year. Also reflected are the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense. FIT expense is shown on Exhibit A-13 (HLP-45), Schedule C-8, line 50.

Line 27 represents an adjustment to AFUDC from the adjusted historical year to the projected test year. The projected test year AFUDC is shown on Exhibit A-13 (HLP-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. AFUDC charged to projects addressing compliance with environmental clean air requirements are not included in this ratemaking adjustment, which is consistent with the Commission's ratemaking treatment. AFUDC increases revenue and NOI, reducing the amount of rate relief requested in the case and is designed to offset the return built into the case for CWIP that is eligible for AFUDC treatment.

Q. Please describe Exhibit A-13 (HLP-38), Schedule C-2.

A. Exhibit A-13 (HLP-38), Schedule C-2, shows the development of the revenue multiplier for the projected test year. The revenue multiplier is a factor that converts a utility's after-tax income deficiency (or sufficiency) into the required change in pre-tax revenue requirement. For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%, and the CIT rate is 0.16%. The resulting revenue multiplier is 1.3381.

Q. Please explain the projected revenues shown on Exhibit A-13 (HLP-39), Schedule C-3.

A. Total projected revenues are shown on line 4. Lines 1, 2, and 3 of the Exhibit A-13 (HLP-39), Schedule C-3 present the sales, wholesale, and other electric revenues that are supported by Company witness Breuring. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLP-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLP-40), Schedule C-4.

A. This exhibit presents the projected test year power supply costs that are supported by Company witness Joshua W. Hahn. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLP-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLP-41), Schedule C-5.

A. Exhibit A-13 (HLP-41), Schedule C-5, presents the other O&M expense for the projected test year as compared to the historical year. The amounts on lines 1 through 25 were provided by Company witnesses Duke, Stewart, Wittbrodt, Guinn, Baker, Gast, Grob, Foster, Conrad, and Breuring. These amounts are supported in their respective direct testimony and exhibits. The amounts on line 26 reflect interest expense on security deposits. The amounts on line 27 represent the return on Forestry "Ramp-up" Regulatory

Asset. The amounts on line 28 represent total DR reconciliation amounts supported by Company witness Gast.

Q. Please explain Exhibit A-13 (HLP-42), Schedule C-5.1.

A. Exhibit A-13 (HLP-42), Schedule C-5.1, provides a summary of inflation and labor merit increases included in other O&M expense. Amounts projected using a method other than inflation and merit are included in column (e). As indicated on this exhibit, various Company witnesses provide detailed calculation of the inflation amounts included in this summary exhibit.

Q. Please explain Exhibit A-13 (HLP-43), Schedule C-6.

A. Exhibit A-13 (HLP-43), Schedule C-6, presents the projected depreciation & amortization expense. Depreciation expense is calculated using book depreciation rates approved by the Commission in Case No. U-20849. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-20844. I discuss the calculation of the amortization expense presented in lines 17 through 26 of Exhibit A-13 (HLP-43), Schedule C-6, in Section III of my direct testimony.

Q. Does the Company have a depreciation case pending before the Commission that could impact depreciation expense and therefore, the revenue deficiency in this proceeding?

A. Yes. The Company filed a depreciation case in Case No. U-21783. The Company has not reflected any of the proposed depreciation rate changes from Case No. U-21783 in the revenue requirement or revenue deficiency in this proceeding. The revenue deficiency herein is based on the depreciation rates currently approved by the Commission. If the

proposed depreciation rates in Case No. U-21783 were approved, the revenue deficiency for the projected test year would be approximately $28.172 million higher than the amount reflected in the instant case. Consistent with Commission practice, any new deprecation rates approved in Case No. U-21783 would only affect customer rates once they are incorporated into the Company's revenue requirement in a general rate case.

Q. Please explain Exhibit A-13 (HLP-44), Schedule C-7, through Exhibit A-13 (HLP-48), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FIT; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to the Company's projected NOI presentation on Exhibit A-13 (HLP-36), Schedule C-1.

Q. Please describe Exhibit A-13 (HLP-49), Schedule C-12.

A. Exhibit A-13 (HLP-49), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year and the corresponding impact on income taxes.

Q. Please describe Exhibit A-13 (HLP-50), Schedule C-13.

A. Exhibit A-13 (HLP-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year.

Q. Why are Exhibit A-13 (HLP-49), Schedule C-12, and Exhibit A-13 (HLP-50), Schedule C-13, included in the presentation?

A. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the projected test year with the amount of rate base that is financed with debt and display the alignment in a transparent manner.

III. REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENTS

A. PowerMIDrive and PowerMIFleet Permanent Programs and Pilot Programs

Q. Has the Commission approved deferred accounting treatment for the PowerMIDrive and PowerMIFleet permanent programs and pilot programs?

A. In Case Nos. U-20134 and U-20697, the Commission approved deferred accounting for expenditures associated with the PowerMIDrive and PowerMIFleet pilot programs. The approach adopted by the Commission envisioned a prudency review of actual expenditures after which the amortization expense, based on a five-year amortization to begin the year after the actual expenditures are recorded, would be included in rates. In addition, the Commission allowed for the deferred balance to be included in rate base earning a return at the authorized rate of return. The Commission also extended this deferred accounting treatment to the permanent programs and reaffirmed the pilot program treatment in its approval of the Settlement Agreement in Case No. U-21224. Most recently, the Commission approved the continuation of the regulatory asset treatment in its final Order in Case No U-21870.

Q. Please describe Exhibit A-173 (HLP-51).

A. Exhibit A-173 (HLP-51) provides the calculation of the projected test year amortization expense, and the projected test year average regulatory asset balances associated with the PowerMIDrive and the PowerMIFleet Programs.

Q. Describe how the projected test year amortization expense and average deferred balance for the PowerMIDrive program were calculated on Exhibit A-173 (HLP-51).

A. Line 1 provides the actual deferred expenditures for the program through 2025. The program expenditures are supported by Company witness Gast. Lines 2 through 7 show

the amortization expense by year. Line 8 shows the total amortization expense for each calendar year, while line 16 shows the proration for the projected test year ending April 30, 2028. The test year amortization expense of $4.9 million has been included in the projected amortization expense on Exhibit A-13 (HLP-43), Schedule C-6, line 17. Line 19 shows the calculation of the average rate base amount for the test year of $10.5 million, which has been included in the projected working capital on Exhibit A-12 (HLP-34), Schedule B-4.

Q. Describe how the projected test year amortization expense and average deferred balance for the PowerMIFleet program were calculated on Exhibit A-173 (HLP-51).

A. Line 9 provides the actual deferred expenditures for the program through 2025. Lines 10 through 14 show the amortization expense by year. Line 15 shows the total amortization expense for each calendar year, while line 17 shows the proration for the projected test year ending April 30, 2028. The test year amortization expense of $2.4 million has been included in the projected amortization expense on Exhibit A-13 (HLP-43), Schedule C-6, line 18. Line 20 shows the calculation of the average rate base amount for the test year of $5.2 million, which has been included in the projected working capital on Exhibit A-12 (HLP-34), Schedule B-4.

B. Karn Units 1 and 2 and Campbell Units 1, 2, and 3 Retention Costs

Q. Please describe Exhibit A-174 (HLP-52).

A. Exhibit A-174 (HLP-52) calculates the projected test year regulatory asset balance and amortization expense for Karn Units 1 and 2 retention costs as ordered by the Commission in Case No. U-20697. The amounts previously deferred in 2022 and 2023 will be fully amortized prior to the start of the test year and as such there is no amortization expense or projected working capital balance included in this instant case.

Additionally, this exhibit calculates the projected test year regulatory asset balance and amortization expense for Campbell Units 1, 2, and 3 retention costs as agreed in the Company's Integrated Resource Plan ("IRP") Settlement Agreement in Case No. U-21090, approved by the Commission on June 23, 2022, and most recently in the Order in Case No. U-21870. The $2.8 million average rate base amount for the projected test year has been included in the projected working capital on Exhibit A-12 (HLP-34), Schedule B-4, and the $3.5 million amortization expense has been included in the projected depreciation and amortization expense on Exhibit A-13 (HLP-43), Schedule C-6, line 20.

C. Campbell Plant Net Book Value

Q. Why were the Campbell plant balances removed from the calculation of the projected test year average CWIP, gross plant, and accumulated depreciation?

A. The Settlement Agreement approved by the Commission in Case No. U-21090 on June 23, 2022, established that in the next rate case filed after the conclusion of the IRP case (Electric Rate Case No. U-21389), the actual remaining net book value of Campbell Units 1, 2, and 3 would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. Moreover, the agreement set annual amortization to allow for the recovery of the remaining net book value and the decommissioning costs through May 2031 for costs associated with Campbell Units 1 and 2 and through May 2040 for costs associated with Campbell Unit 3. In addition, the Company is allowed the following:

> … to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those

> units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

The Commission most recently approved the treatment described above in the Order in Case No. U-21870.

Q. Please describe Exhibit A-175 (HLP-53).

A. Exhibit A-175 (HLP-53) calculates the regulatory asset balance and amortization expense for Campbell Units 1, 2, and 3. The exhibit starts with the regulatory asset balances as of December 31, 2025 for Campbell Units 1 and 2 in column (c), line 3, and for Campbell Unit 3 in column (c), line 7. These balances are rolled forward by subtracting the amortization expense for the subsequent periods. The amortization expense is calculated in line 2 through May 2031 for Campbell Units 1 and 2. The amortization expense for Campbell Unit 3 is calculated in line 6 through May 2040. Finally, the 13-month average regulatory asset balances for the projected test year period are included on lines 4 and 8, column (f), for Cambell Units 1 and 2 and Campbell Unit 3, respectively.

Q. How are the results of these exhibits included in the instant case?

A. The average rate base amount for the projected test year ($259.9 million for Campbell Units 1 and 2, and $699.0 million for Campbell Unit 3) have been excluded from the test year projected working capital on Exhibit A-12 (HLP-34), Schedule B-4. The amortization expense ($72.5 million for Campbell Units 1 and 2, and $55.6 million for Campbell Unit 3) has been included in the projected depreciation and amortization expense on Exhibit A-13 (HLP-43), Schedule C-6, line 21.

Q. Why did the Company exclude Campbell Units 1, 2, and 3 projected regulatory asset balances from working capital, and how is the Company addressing the lower return on equity approved for the Campbell regulatory asset after the retirement date of the units?

A. As noted above, the Settlement Agreement approved by the Commission in Case No. U-21090 requires the overall return on the Campbell regulatory asset to reflect a return on equity of 9% after retirement of the units in May 2025. To accomplish this, I have excluded the regulatory asset from the balances underlying the base rate revenue deficiency calculations. Instead, I am supporting a separate return calculation for the Campbell regulatory asset on Exhibit A-179 (HLP-57) with an ROE of 9%. The resulting return on the Campbell regulatory asset is included in the Company's overall revenue deficiency presentation on Exhibit A-11 (HLP-28), Schedule A-1, line 9.

D. Decommissioning and Ash Disposal Costs

Q. Did the Commission approve a regulatory asset treatment for the decommissioning and ash disposal costs for certain coal units?

A. Yes. First, the Settlement Agreement approved by the Commission in Case No. U-20849 established the following:

> The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset

> account are net of any accumulated depreciation amounts. [MPSC Case No. U-20849, December 9, 2021 Order, Exhibit A, pages 2-3.]

Second, the Settlement Agreement approved by the Commission in Case No. U-21090 established the following:

> [T]he Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:
>
> a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
>
> b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

Finally, the Settlement Agreement approved by the Commission in Case No. U-21224 provided the following:

> The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024. [MPSC Case No. U-21224, January 19, 2023 Order, Exhibit A, page 7.]

Most recently, the Commission approved the treatment described above in the Order in Case No. U-21870.

Q. Please describe Exhibit A-176 (HLP-54) and Exhibit A-177 (HLP-55).

A. Exhibit A-176 (HLP-54) presents the calculation of the projected test year regulatory asset balance and related amortization expense associated with Karn Units 1 and 2 decommissioning costs, totaling $53.2 million and $12.2 million, respectively. This exhibit also includes the projected test year amortization expense of approximately $4.9 million for Campbell Units decommissioning costs.

Exhibit A-177 (HLP-55) presents the projected test year regulatory asset balance and amortization expense for ash disposal costs related to Karn Units 1 and 2, Classic 7, and Campbell Units, totaling approximately $94.3 million and $11.2 million, respectively.

In total, the combined average regulatory asset balance of $147.5 million reflected on these exhibits has been included in projected working capital on Exhibit A-12 (HLP-34), Schedule B-4. The combined amortization expense of $28.3 million has been included in projected depreciation and amortization expense on Exhibit A-13 (HLP-43), Schedule C-6.

E. Pension/OPEB Volatility Mechanism

Q. Please explain Exhibit A-178 (HLP-56).

A. Exhibit A-178 (HLP-56) calculates the projected test year regulatory asset and liability balances, and the corresponding amortization expense, related to the Pension and OPEB Volatility Mechanism approved by the Commission in Case Nos. U-21224, U-21389, U-21585, and U-21870. This volatility mechanism allows the Company to defer for future recovery or refund pension and OPEB expenses above or below approved amounts. The net total of $26.1 million regulatory liability for the projected test year has been included in the projected working capital on Exhibit A-12 (HLP-34), Schedule B-4, and the total of

($2.5) million amortization expense has been included in the projected other O&M expense on Exhibit A-13 (HLP-41), Schedule C-5, line 18.

F. SAP S/4HANA Implementation Project Recovery

Q. Please describe the SAP S/4HANA Project.

A. The SAP S/4HANA Project will modernize the Company's current Enterprise Resource Planning SAP solution that will reach the end of mainstream vendor maintenance on December 31, 2027. The completion of this project is crucial. Operating the system beyond the end of the support date creates significant risks including the inability to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber security protection. The project is described in more detail in the testimony of Company witness Baker.

Q. Please describe what the Company is requesting related to the SAP S/4HANA Project in the instant case.

A. The Company requests the continuation of the accounting treatment approved in Case No. U-21870 to defer to a regulatory asset the O&M expenses associated with the project. This results in no O&M expenses associated with the project being included for recovery in this instant case. Additionally, the return on amounts included in construction work in progress have been offset by allowance for funds used during construction.

Exhibit A-12 (HLP-34), Schedule B-4 reflects the projected regulatory asset balance associated with deferred investment O&M expenses of $33.6 million for the test year as supported by Company witness Baker. Pursuant to the Commission's Order in Case No. U-21870, the Company will amortize the deferred costs over a 15-year period.

Q. Does the Company have an additional proposal regarding the amortization of SAP Project costs?

A. Yes. Pursuant to the Commission's Order in Case No. U-21870, the Company will recover both capital and deferred O&M costs over a 15-year period. Additionally, as described in the pending gas rate case, Case No. U-21981, the Company proposes delaying the start of amortization of all SAP Project-related costs until all releases are complete and the total costs can be reviewed by the Commission to confirm their reasonableness and prudence. This approach streamlines accounting practices, reduces administrative complexity, and simplifies tracking and reporting of overall project related expenditures. This approach ensures that cost recovery matches the timing of benefits delivered to the Company and customers.

G. Line Clearing Program Ramp-up

Q. What is the Company proposing with respect to its Line Clearing Program expense in this case?

A. In Case No. U-21870, the Company was authorized to increase its LVD Line Clearing Program O&M expense above historical levels to move toward achieving a five-year clearing cycle and more aggressive line clearing on targeted three-phase primary lines. As discussed by Company witness Stewart, this ramp-up in line clearing spending is occurring over a five-year period. Upon completion of the ramp-up in 2031, the Company expects to maintain a steady-state five-year clearing cycle for its LVD system. In this case, the Company proposes to continue the same deferred accounting mechanism for "ramp-up" forestry expenses approved by the Commission in Case No. U-21870. The mechanism

permits the Company to defer line clearing expenses that exceed approved baseline line clearing expenses.

Q. What "ramp-up" amounts did the Commission previously approve for deferral in the Company's previous rate case?

A. In Case No. U-21870, the Commission approved a baseline line clearing expense of $186.68 million and a deferral of $22.24 million for the test year ending April 30, 2027. On a calendar-year basis, this results in a deferral amount of $14.4 million for calendar year 2026, as shown in Exhibit A-180 (HLP-58).

Q. Is the Company requesting Commission approval to defer additional "ramp-up" expenses within the instant case for calendar years 2027 and 2028?

A. Yes. The Company is requesting Commission approval to defer forestry "ramp-up" expenses of approximately $46.7 million and $69.5 million for calendar years 2027 and 2028, respectively, as detailed on Company witness Stewart's Exhibit A-186 (SES-1), line 34. The proposed baseline expenses are shown on line 33 of the same exhibit. Company witness Stewart's direct testimony supports the calculation of these baseline and

"ramp-up" funding amounts. Regardless of total forestry expenses, the amount deferred to the regulatory asset would not exceed the requested funding amounts described above.

Q. What other parameters did the Commission specify related to the deferral of ramp-up expenses associated with the Line Clearing Program?

A. In addition to approving the baseline line clearing expenses and the deferral of ramp-up expenses as a regulatory asset, the Commission specified that the applicable return on the regulatory asset should be calculated using the Company's prevailing short-term debt rate.

Q. What has been included in the revenue requirement in this rate case filing?

A. The Company has included the approved and requested deferred ramp-up expenses associated with the LVD Line Clearing Program as a regulatory asset. However, consistent with the Commission's direction that the regulatory asset earn a return only at the short-term debt rate, the asset has been excluded from the working capital calculation. The Company has calculated the return on the projected test year regulatory asset average balance using the Company's proposed short-term debt rate, as shown in Exhibit A-180 (HLP-58) and included the resulting return on Exhibit A-13, Schedule C.5 (HLP-41), line 27.

G. March/April 2025 Extraordinary Storm Deferral Regulatory Asset

Q. Provide the background of the March/April 2025 storms.

A. Beginning on March 28, 2025, Consumers Energy experienced a series of severe, multi-wave weather events across its electric service territory that resulted in widespread system damage and customer outages. The initial event produced significant ice accumulation and high winds across northern Michigan, prompting the Governor of Michigan to issue emergency declarations for 13 counties and later being confirmed by the

National Weather Service as the most severe ice storm in the region in over 100 years. Subsequent weather events on March 30 and April 2–3 included severe thunderstorms, damaging winds, additional freezing precipitation, and 14 confirmed tornadoes, representing the highest single-day tornado count in Michigan since 2001. Collectively, these events caused extensive damage to Consumers Energy's electric infrastructure, including approximately 7,600 downed wires and outages affecting more than 391,000 customers. Restoration efforts required the replacement of 636 transformers, 1,810 poles, and approximately 220 miles of conductor, supported by more than 900 electric line crews and 300 forestry crews operating under challenging field conditions. Further detail on the 2025 March/April storm is included in the testimony of Company witness Jeffrey P. Dickey.

Q. Please summarize the storm deferral mechanism authorized by the Commission.

A. On April 23, 2025, the Company filed an application in Case No. U-21914, requesting ex parte accounting authority to defer the extraordinary O&M expenses associated with the March/April 2025 storm events. The Commission order approved the Company's request to record the March/April 2025 extraordinary storm-related O&M costs as a regulatory asset. As described by Company witness Dickey, the Company deferred $52 million of O&M expense, as shown on Exhibit A-184 (HLP-62), line 1.

Q. What requirements did the Commission establish regarding the Company's operational response for the March/April 2025 storms?

A. The Commission order in Case No. U-21914 requires the Company to provide comprehensive documentation of its operational response to the March/April 2025 storms, including detailed storm data, a breakdown of capital and O&M unit costs for both internal

and contractor crews, and evidence that restoration efforts were conducted in a cost-effective manner while achieving optimal customer restoration. Company witness Dickey addresses these requirements in his direct testimony.

Q. What requirements did the Commission establish regarding the evaluation of cost-recovery options for the deferred storm costs?

A. The Commission directed the Company to provide a comprehensive comparison of potential cost-recovery options in any future filing seeking recovery of the deferred storm costs. The comparison must include a potential securitization of the regulatory asset, amortization of the regulatory asset over various time periods without a return, and any other cost-recovery options that the Company may identify. The Commission also requires the Company to demonstrate why its preferred approach is in the best interest of customers.

In response, the Company evaluated securitization and multiple amortization periods to assess customer bill impacts, total cost implications, and administrative burden associated with each option, including implementation complexity and ongoing compliance requirements. This evaluation was undertaken to ensure that any proposed recovery method is affordable for customers and administratively efficient to implement. Consistent with the Commission's order, none of the options evaluated include a return on the regulatory asset.

Q. Why did the Company evaluate securitization as a potential cost-recovery method?

A. As noted above, the Commission explicitly required the Company to evaluate securitization as a potential recovery mechanism. Securitization can, under certain conditions, reduce customer costs by replacing traditional utility financing with lower-cost, debt-only financing. As securitization transactions are statutorily authorized in Michigan

and have been used for extraordinary or non-recurring costs, the Company assessed whether securitizing the March/April 2025 storm regulatory asset could provide meaningful customer savings relative to other recovery methods. This evaluation, as described in the direct testimony of Company witness Bleckman, considered the size and nature of the regulatory asset, the expected transaction costs, potential customer savings, if any, and the administrative requirements associated with undertaking a securitization transaction of this size.

Q. What were the results of the Company's evaluation of securitization?

A. Based on the analysis performed by Company witness Bleckman, the Company concluded that securitization is not an economical or practical cost-recovery option for the March/April 2025 storm regulatory asset. Company witness Bleckman's assessment shows that the transaction and administrative costs associated with issuing securitization bonds are high relative to the size of the regulatory asset, eliminating any potential customer savings. In addition, the securitization process would impose substantial administrative burdens, including statutory filing requirements and ongoing compliance obligations, all of which are disproportionate to the size of the regulatory asset. For these reasons, and those discussed by Company witness Bleckman, securitization does not represent the best cost-recovery option for customers, and the Company does not propose to pursue a securitization transaction further in this case.

Q. How did the Company evaluate different amortization periods for recovering the March/April 2025 storm regulatory asset?

A. The Company evaluated amortization periods of one year, three years, and five years to balance customer affordability impacts associated with the recovery of the $52 million

regulatory asset with the need for timely recovery. As the Commission order requested an evaluation without the Company earning a return on the regulatory asset, the total amount recovered from customers is the same under each option. As the Company does not earn any return on the regulatory asset, extending recovery over a longer period effectively requires the Company to finance the unrecovered balance without compensation. This makes it especially important that the recovery period is not excessively long, as doing so places additional burden on the Company's financial metrics. However, the timing of recovery affects both the annual bill impact for customers and the Company's financial metrics.

The Company recognizes the potential affordability impacts associated with recovery of the regulatory asset and believes that spreading the costs over time is appropriate to alleviate near-term bill pressure, while still ensuring the regulatory asset is recovered within a reasonable period. As explained in the testimony of Company witness Bleckman, extending recovery too long leaves a larger unrecovered balance on the Company's balance sheet, which negatively affects key credit metrics that have already shown recent deterioration. The Company evaluated these trade-offs to determine which amortization period best balances affordability, timely recovery, and the Company's financial health.

Q. What are the implications of using a one-year, three-year, or five-year amortization period?

A. The table below summarizes the annual amortization amount under each of the recovery periods and the corresponding residential annual impact (in dollars).

Amortization Period	Annual Amortization Amount	Annual Residential Bill Impact ($)
1 Year	$51,997	$21.34
3 Years	$17,332	$ 7.11
5 Years	$10,399	$ 4.27

As shown in the table, a one-year amortization period results in the highest annual cost and therefore the highest near-term bill impact for customers. While this option provides the most rapid recovery, the Company believes it undermines its approach to customer affordability by concentrating the full cost into a single year. The five-year amortization period spreads the same total cost over a longer timeframe, resulting in the lowest annual bill impact. However, as described by Company witness Bleckman, extending recovery over five years negatively affects key credit metrics that are already under pressure. Exacerbating the credit metric issues can ultimately increase the Company's cost of borrowing and reduce financial flexibility, limiting the Company's ability to invest in system reliability and resiliency and increasing overall costs to customers.

The Company also notes that amortizing the regulatory asset imposes virtually no administrative burden, as recovery is incorporated directly into base rates. This stands in contrast to a potential securitization, which requires extensive statutory filings, bond issuance processes, and ongoing compliance obligations that are disproportionate to the size of this regulatory asset.

For these reasons, neither the one-year nor the five-year amortization period provides the optimal balance of customer affordability and financial stability.

Q. Why is a three-year amortization period the best option for customers?

A. A three-year amortization period provides the most balanced and reasonable approach. It smooths the customer bill impact over several years, improving affordability relative to a one-year recovery, while avoiding the prolonged recovery timeline and negative credit metric impacts associated with a five-year period. This approach reflects the Company's commitment to keeping customer affordability top of mind while still ensuring timely recovery. For these reasons, the Company concludes that a three-year amortization period of the regulatory asset best serves customers by balancing affordability, timely recovery, and the Company's financial stability.

Q. How is the March/April 2025 storm regulatory asset treated in the instant case?

A. The $52 million regulatory asset associated with the March/April 2025 storms has been excluded from the Company's projected working capital balance and therefore does not earn a return, consistent with the Commission's directive in Case No. U-21914. As outlined above, the Company proposes recovering the regulatory asset through a three-year amortization period, which is reflected on Exhibit A-184 (HLP-62). This results in approximately $17.3 million in amortization expense beginning in the test year, as shown on Exhibit A-13 (HLP-43), Schedule C-6, line 25.

Q. Did the Company evaluate whether it would be appropriate to recover the regulatory asset through a separate surcharge?

A. Yes. As part of its evaluation of potential cost-recovery approaches, the Company considered whether establishing a separate surcharge to recover the March/April 2025 storm regulatory asset would be appropriate. The Company determined that implementing a standalone surcharge for this regulatory asset would introduce unnecessary

administrative complexity and cost. Establishing a surcharge requires separate tariff administration, billing system modifications, and ongoing compliance tracking to ensure accurate application and eventual removal of the surcharge. These administrative requirements are disproportionate to the size of the regulatory asset and would increase internal workload and billing complexity without providing meaningful benefits to customers. For these reasons, the Company concluded that recovering the storm deferral regulatory asset through base rates, rather than through a separate surcharge, is a more efficient and administratively practical approach.

H. Itron Refund – Regulatory Liability (Case No. U-21502)

Q. Please explain the background of the Itron regulatory liability and how it was addressed in the Settlement Agreement approved in Case No. U-21502.

A. The Itron regulatory liability arises from circumstances that led to the Commission's investigation in Case No. U-21502, including issues related to meter performance, estimation practices, and new service installations. The May 23, 2024 settlement agreement required the establishment of a regulatory liability account to record any monetary proceeds or credits the Company received from Itron related to these issues. The Company was ordered to ensure that, following the resolution of all claims with Itron, the associated regulatory liability balance equals $3 million (inclusive of any proceeds or credits received). The Company was further ordered to propose, in a future rate case, a refund of the full amount of the regulatory liability to customers, either through direct bill credits or an offset to base rates.

Q. Please describe Exhibit A-185 (HLP-63) and what has been included in the projected test year.

A. Exhibit A-185 (HLP-63) presents the recorded regulatory liability balance established pursuant to the settlement agreement in Case No. U-21502 and reflects the Company's proposal to refund $3 million to customers through an offset to base rates. This is accomplished through a $3 million credit to amortization expense in the projected test year, as shown on Exhibit A-185 (HLP-63), and Exhibit A-13 (HLP-43), Schedule C-6, line 26. Additionally, the Company has also incorporated the corresponding impact on projected working capital, as presented on Exhibit A-12 (HLP-34), Schedule B-4.

IV. DISTRIBUTION DEFERRAL

Q. Did the Commission approve the deferral of the revenue requirement of certain distribution capital spending for the period of March 1, 2025 to February 28, 2026?

A. Yes. In its March 21, 2025 Order in Case No. U-21585, the Commission approved deferred accounting for the return on, return of, and property taxes associated with actual capital spending from March 1, 2025 through February 28, 2026 above the following amounts until rates were reset in a subsequent case: $267.3 million for new business, $206.2 million for reactive demand failures, and $51.9 million for asset relocations. Subsequently, in its March 27, 2026 Order in Case No. U-21870, the Commission approved to extend the deferral of the revenue requirement associated with capital spending for the aforementioned time period above rate levels until actuals are included in rates. The capital spending amounts approved in Case No. U-21870 were: $365.9 million for new business, $188.7 million for reactive demand failures, and $85.3 million for asset relocations.

Q. Are you sponsoring any exhibits related to the March 1, 2025 to February 28, 2026 distribution deferral in this case?

A. Yes. Exhibit A-182 (HLP-60) is presented in support of the distribution deferral revenue requirement.

Q. Did the Company have actual capital spending above the amounts included in the rates for new business, reactive demand failures, and asset relocation?

A. Yes. As provided on page 2 of Exhibit A-182 (HLP-60), the Company had actual capital spending for the period of March 1, 2025 to February 28, 2026 above the amounts included in Case No. U-21585 for all three of the referenced capital spending programs. The spending was below the amount included in rates in Case No. U-21870 for new business but exceeded the amounts for demand failures and asset relocations individually and in total. When compared to the capital levels included in rates in Case No. U-21870, actual spending was below the authorized amount for the new business program; however, that underspending was more than offset by higher-than-approved spending for reactive demand failures and asset relocation. As a result, total actual capital spending across all three programs, in aggregate, exceeded the total capital spending authorized in Case No. U-21870.

Q. Are any of these programs included in the Investment Recovery Mechanism ("IRM") sponsored by Company witness Myers in the instant case?

A. No. The IRM proposal sponsored by Company witness Myers is designed for programs unrelated to new business, reactive demand failures, and asset relocations.

Q. Have you calculated the return on, return of, and property tax related to the capital spending above the amounts included in rates for new business, reactive demand failures, and asset relocation?

A. Yes. Exhibit A-182 (HLP-60) provides the calculation of the return on, return of, and property tax expense attributable to the capital spending for the period of March 1, 2025 through February 28, 2026 above the amounts approved in Case No. U-21585 and Case No. U-21870. The $25.0 million total amount was calculated to represent the additional revenue requirement from March 1, 2025 through April 30, 2027, that would have been built into rates if the additional capital spending would have been included.

Q. Was the Company able to record revenue for the full return associated with the capital spending above amounts included in rates?

A. No. Per accounting guidance, the Company was not able to record revenue associated with the return on equity portion of the cost of capital. Revenue related to the return on equity will not be recorded until collected from customers. The regulatory asset account related to this deferral includes the return on equity but there is a contra regulatory asset account that offsets the regulatory asset by the amount related to the return on equity. The regulatory asset account houses the total revenue requirement.

Q. How does the Company propose to collect the total deferral from customers?

A. Similar to the recovery of the deferral surcharge approved in Case No. U-21870, the Company proposes that a 12-month charge be established to collect the $25.0 million total deferral. The Company further proposes that the charge be implemented for service rendered on and after the effective date of the final order in the instant case and terminating

after 12 months. Company witnesses Davis and Grondin sponsor the allocation and design of the charge, respectively.

Q. Did the Commission approve the deferral of the revenue requirement of certain distribution capital spending for the test year ending April 30, 2027?

A. Yes. In its March 27, 2026 Order in Case No. U-21870, the Commission also approved deferred accounting for the return on, return of, and property taxes associated with actual capital spending above the approved amounts for the test year ending April 30, 2027 for new business, reactive demand failures, and asset relocations until actual capital spending is included in rates. The approved amounts for these programs for the test year ending April 30, 2027, are shown in Exhibit A-183 (HLP-61).

Q. Is the Company making a proposal in the instant case regarding the distribution deferral mechanism?

A. Yes. The Company is requesting the Commission to approve the continuation of the deferral mechanism approved in Case No. U-21870 for the test year ending April 30, 2028.

V. DEMAND RESPONSE

Q. Please describe Exhibit A-181 (HLP-59).

A. Exhibit A-181 (HLP-59) is a three-page exhibit that calculates the projected test year revenue requirement for DR programs as included in this case. The first page of the exhibit summarizes the total projected test year revenue requirement for DR programs, including the 2025 incentive and over-recovery as discussed in more detail by Company witness Gast. This first page includes the results of the second and third page. The second page of the exhibit calculates the projected test year revenue requirement for the residential DR programs, and the third page of the exhibit calculates the projected test year revenue

requirement for the commercial and industrial DR program. This exhibit establishes the revenue requirement included in rates as proposed in the instant case. Should the Commission adjust the capital or O&M spending requested for DR, it would be necessary to update this exhibit to reflect those changes. As described further by Company witnesses Grondin and Gast, the Company is not including a separate surcharge for the DR program.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Daniel A. Schmoekel, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Engineering - LVD Statewide Programs. In this role I have responsibility for Streetlighting, low voltage distribution ("LVD") Resource Planning, Infrastructure Attachments, and Statewide Integration.

Q. What is your educational background?

A. I graduated from Michigan Technological University with a Bachelor of Science Degree in Civil Engineering in 2006. In addition, I graduated from Grand Valley State University in 2018 with a Master of Business Administration degree. I earned a Professional Engineering license (State of Michigan) in 2011, and achieved certification as a Project Management Professional (Project Management Institute) in 2013.

Q. Please describe your business experience.

A. Following graduation from Michigan Technological University, I worked as an engineer at OHM Advisors (Livonia, Michigan) until 2008. In 2008, I joined Consumers Energy as a project engineer responsible for capital improvement projects at the B.C. Cobb Generating Facility ("Cobb"), a now-retired, five-unit power plant located in Muskegon, Michigan. In 2010, I accepted a position as a Mechanical Maintenance Supervisor at Cobb, where I was responsible for establishing the work schedule and prioritizing work assignments for mechanical maintenance personnel, as well as ensuring policies and practices of the Working Agreement were followed. In 2011, I accepted a position as a

System Owner at the J.H. Campbell Complex ("Campbell") in West Olive, Michigan, a three-unit coal-fired generating facility. As a System Owner, my responsibilities included providing engineering and technical direction to identify and correct operational, design, and maintenance related issues. I was then promoted to Production Engineer at Campbell Unit 3, where I monitored plant operating parameters and identified/investigated equipment deficiencies. In 2015, I was promoted to Production Lead at Campbell Unit 3. In this position, I ensured interim acceptance of all Campbell Unit 3 Air Quality Control Systems related equipment per applicable Consumers Energy policies and procedures, performed technical reviews of system operating procedures/new equipment modification designs, and managed the Operating and Maintenance and capital budgets for the Campbell Unit 3 Operations Department. In 2018, I transferred to the Operations, Finance, and Planning organization as the Electric Dispatch Principal Team Lead. In this role, I had operational responsibility for LVD dispatching and management of the planning and scheduling functions of short cycle streetlight work orders for 30 Headquarters across Consumers Energy's electric service territory. In October 2021, I accepted the role of Manager of Streetlight Programs. In this role I oversaw billing reconciliations, asset management, and contracts, and managed budgets for street lighting programs. In March 2023, I was promoted to Asset Strategy Manager (and then promoted to Senior Strategy Manager in July 2023). In this role, I developed prioritized plans in alignment with Company goals for improvement of electric assets, and safety and compliance. In September 2025 I accepted the position of Director of Engineering - LVD Statewide Programs. In this role I have responsibility for Streetlighting, LVD Resource Planning, Infrastructure Attachments, and Statewide Integration.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in the Company's 2022, 2023, 2024, and 2025 Electric Rate Case Nos. U-21224, U-21389, U-21585, and U-21870 respectively.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Streetlight Program requests in this case. Toward that end I will:

- Describe Consumers Energy's streetlighting assets and provide an overview of the Company's strategic plan for management of those assets. Aspects of the strategic plan include streetlighting outage restoration performance, accelerated/planned conversions, streetlighting resources, planned maintenance, and customer outage reporting;

- Support the reasonableness and prudence of the capital expenditures for the conversion of cobrahead, post top, and center suspension streetlights for the historical year ended December 31, 2025, the 16-month bridge period beginning January 1, 2026, and ending April 30, 2027, and the projected test year beginning May 1, 2027, and ending April 30, 2028;

- Support the reasonableness and prudence of the capital expenditures for the conversion of high intensity discharge ("HID") cobrahead and post top streetlights that are located in the vicinity of failed cobrahead and post top fixtures for the historical year ended December 31, 2025, the 16-month bridge period beginning January 1, 2026, and ending April 30, 2027, and the projected test year beginning May 1, 2027, and ending April 30, 2028;

- Support the reasonableness and prudence of the capital expenditures for the installation of new customer-requested streetlighting assets for the historical test year ended December 31, 2025, the 16-month bridge period beginning January 1, 2026, and ending April 30, 2027, and the projected test year beginning May 1, 2027, and ending April 30, 2028; and

- Discuss the Company's streetlight outage restoration performance.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into the following sections.

I. Consumers Energy Company-owned Streetlight Assets

II. Consumers Energy Plan for Streetlights

III. Streetlight Outage Reporting and Restoration

IV. LED Streetlight Equivalency Evaluations and New Business

V. Conversion of Cobrahead, Post Top, and Center Suspension Streetlights

VI. Planned Streetlight Conversions

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Emily M. Duke sponsors the operations and maintenance ("O&M") expense associated with operating the streetlighting program, whereas I will be supporting the capital expenditures associated with operating the streetlighting program.

Company witness Brittani A. Gray sponsors revising the GUL lighting rate tariff.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (DAS-1)	Schedule B-5.10	Summary of Actual and Projected Electric Capital Expenditures for the Years 2021 through 2028.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

I. CONSUMERS ENERGY COMPANY-OWNED STREETLIGHT ASSETS

Q. Please provide an overview of the Company's streetlight assets.

A. The Company owns and maintains approximately 175,000 streetlights. The majority of these streetlights are cobrahead fixtures (see Figure 1 below). In addition to the 121,000 cobrahead fixtures, the Company has approximately 11,000 center suspension streetlights

and approximately 43,000 post-top fixtures, which make up the total quantity of 175,000 streetlights.

FIGURE 1
COBRAHEAD FIXTURE WITH LIGHT EMITTING DIODE



The streetlights the Company owns primarily fall in one of two buckets: HID and light emitting diode ("LED").

HID luminaires include mercury vapor ("MV"), high pressure sodium ("HPS"), and metal halide ("MH"). The MV, MH, and LED streetlights typically have a similar color temperature (white light) whereas the HPS streetlights typically have an amber color.

Q. Is the HID technology obsolete?

A. Not entirely. Pursuant to the Energy Policy Act of 2005,[1] the MV technology has been discontinued and is obsolete. As I will discuss later in this testimony, the Company has taken a planned conversion approach to replacing the MV technology. Manufacturers are discontinuing HID offerings and the Company is replacing HID technology for cobrahead,

[1] PL 109-58; 119 Stat 631. See Section 135.

post top, and center suspension fixtures. The continuously evolving LED technology is far more energy efficient than any of the available HID technologies.

II. CONSUMERS ENERGY'S PLAN FOR STREETLIGHTS

Q. Please provide an update on the Company's continuing efforts to improve its streetlighting service.

A. As I will discuss later in this direct testimony, the Company has engaged additional resources, implemented its Streetlight Outage and Restoration ("SOAR") application, completed a streetlight patrol and fix initiative, completed an initiative for advanced lighting controls, established long duration outage monitoring and reporting, and developed a modified conversion plan for its HID cobrahead and post top fixtures—all to support improved outage restoration performance.

Q. How has the Company collaborated with its stakeholders in arriving at some of the program improvements?

A. The Company has continuously supported interaction with its customers, including the Michigan Municipal Association for Utility Issues ("MI-MAUI"), in developing its streetlighting improvements. The Company met with MI-MAUI eight times in 2025 to discuss streetlighting reliability reporting, and operational progress to identify opportunities for improvement and enhance customer experiences. Throughout the collaborative process, the Company has been receptive to suggestions for process improvements.

Q. Does the Company plan to continue its collaboration with its stakeholders to identify future program improvements?

A. Yes. Consistent with the Commission's suggestion in Case No. U-20963 to continue to collaborate with MI-MAUI and other parties to address streetlighting concerns, the Company and MI-MAUI continue to meet bi-monthly to discuss relevant street lighting topics.

Q. Was streetlighting reliability a topic in the MPSC electric distribution audit in Case No. U-21305?

A. No. Streetlighting reliability was not a topic in Case No. U-21305.

Q. Does the Company have a long-term plan documented for improving the reliability of its streetlights?

A. Yes. The ideal state for the Company's streetlight program is to repair or replace streetlights only at the end of the component lifecycle, rather than having to replace components that fail early. Extending the lifecycle of the luminaire reduces repair expenses across the Company's streetlight portfolio. The Company discusses streetlighting in its revised Reliability Roadmap. Please see Exhibit A-95 (EMD-11), for the Company's revised Reliability Roadmap.

III. STREETLIGHT OUTAGE REPORTING AND RESTORATION

Q. What actions has the Company taken to improve streetlight outage performance?

A. In 2022, the Company initiated a proactive plan to convert HID cobrahead streetlights located in the vicinity of failed cobrahead streetlights to LED because every proactive conversion eliminates a future HID streetlight outage. In 2025, this tactic was extended to post top lights as well. To date, 5,711 HID streetlights have been proactively converted to

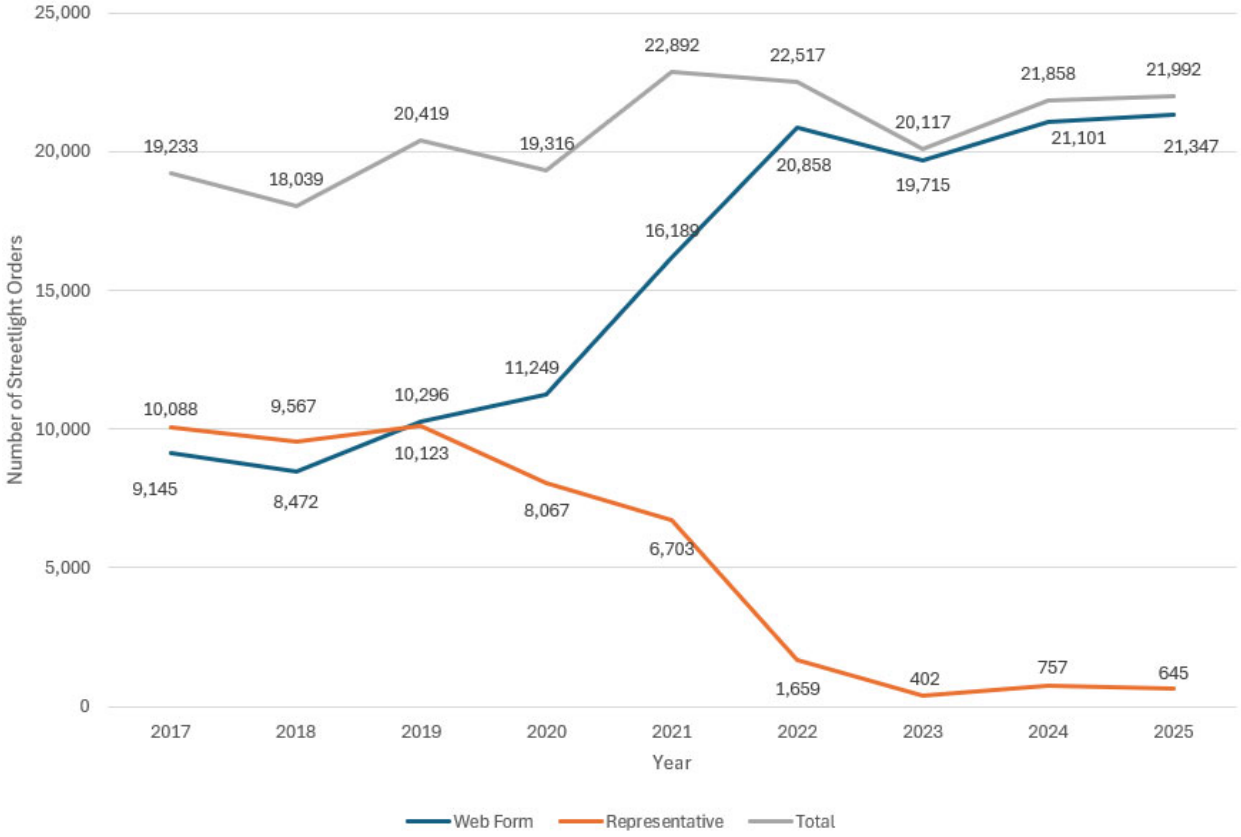
LED, resulting in $597,000 savings for the customer due to reduced truck rolls. The Company completed the patrol and fix initiative, and advanced lighting controls initiatives in 2022 (discussed later in this direct testimony). Additionally, the Company is evaluating different contracting strategies to improve outage duration.

In 2025, the Company defined parameters for long duration outages. The Company implemented daily and weekly monitoring of all long cycle outages. This created focus on restoration of streetlight outages within 125 days, greatly reducing the quantity of outages exceeding 125 days.

Q. Please describe the Company's 2025 streetlight outage restoration performance.

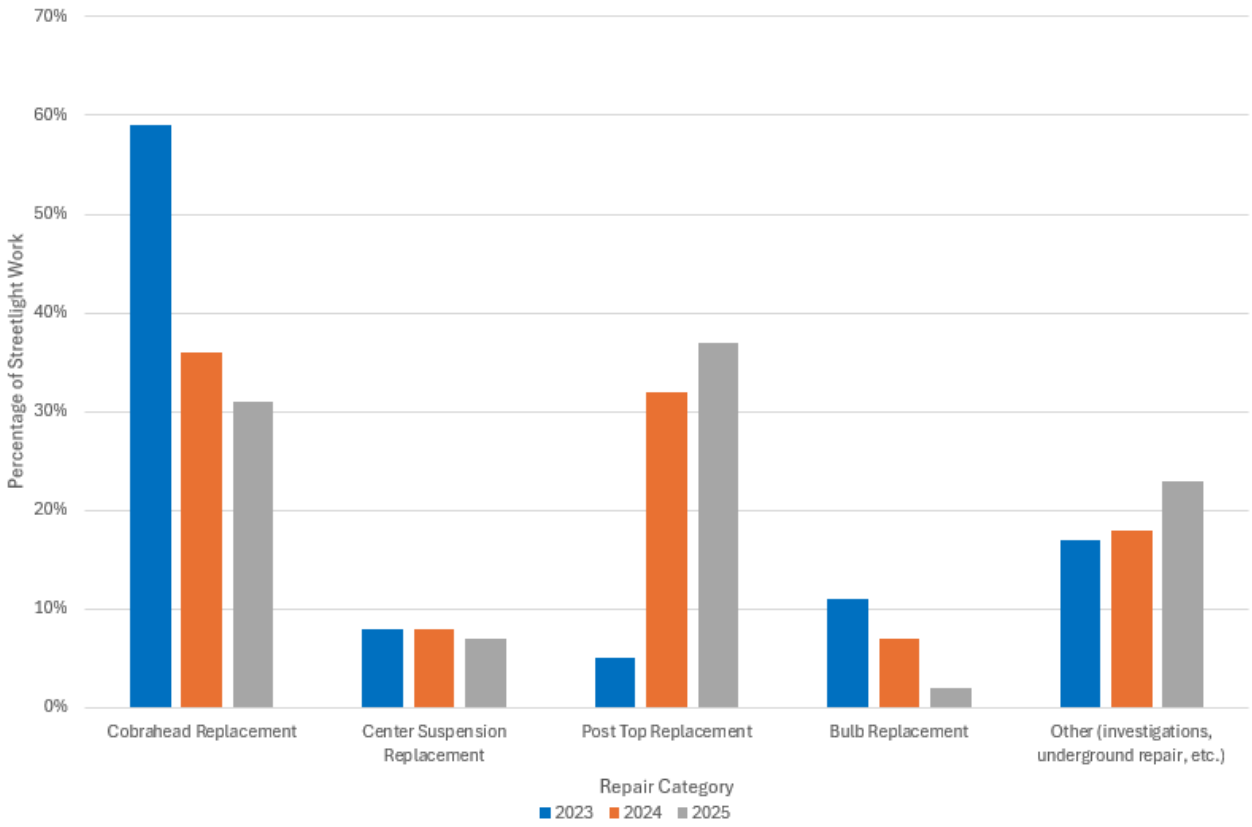
A. A total of 21,992 streetlight incidents were investigated in 2025, 97% of which were reported via the SOAR application. Historical streetlight order creation by type is shown in Figure 2 below where the SOAR Application (Web Form) constitutes 21,347 of the incidents.

Figure 2
Streetlight Orders by Creation Type



These incidents between 2022 and 2024 resulted in the work as shown in Figure 3 below.

Figure 3
Work Type Breakdown of 2023 through 2025 Streetlight Orders



In 2025, the average streetlight outage duration was 11.50 days and the median outage duration was 6 days. In 2025, the average outage and median outage duration improved compared to 2024 by 3.15 days and 1 day, respectively. Activities to improve streetlight outage performance are discussed later in this direct testimony.

Q. Does the Company prioritize other work ahead of streetlight outage restoration?

A. The Company prioritizes public safety related orders and emergent service restoration ahead of streetlight outage repairs. The workers who complete streetlight repairs are the same workers who perform emergent service restoration and respond to downed wire orders. While the Company has a financial incentive to prioritize streetlight repairs

because it is required to compensate streetlight customers with a streetlight outage credit pursuant to its tariff, it must prioritize restoration work in order of public impact.

Q. What does the Company believe are the causes or contributing factors of the increase in the number of streetlight orders from 2017 to 2025?

A. The Company believes the increased number of orders reflected in Figure 2 above reflects greater reporting of outages due to implementation of the SOAR application—not that the Company is necessarily experiencing more outages – because customers now have an easy-to-use self-service application for reporting streetlight outages. Additionally, the Company is no longer performing any lamp maintenance/replacement as it is converting HID cobrahead and post top fixtures upon failure. This practice is expected to result in a relatively uniform conversion of cobrahead, center suspension, and post top fixtures across nearly all municipalities and will ultimately lead to reduced streetlight orders due to the reduced maintenance required for LED streetlights.

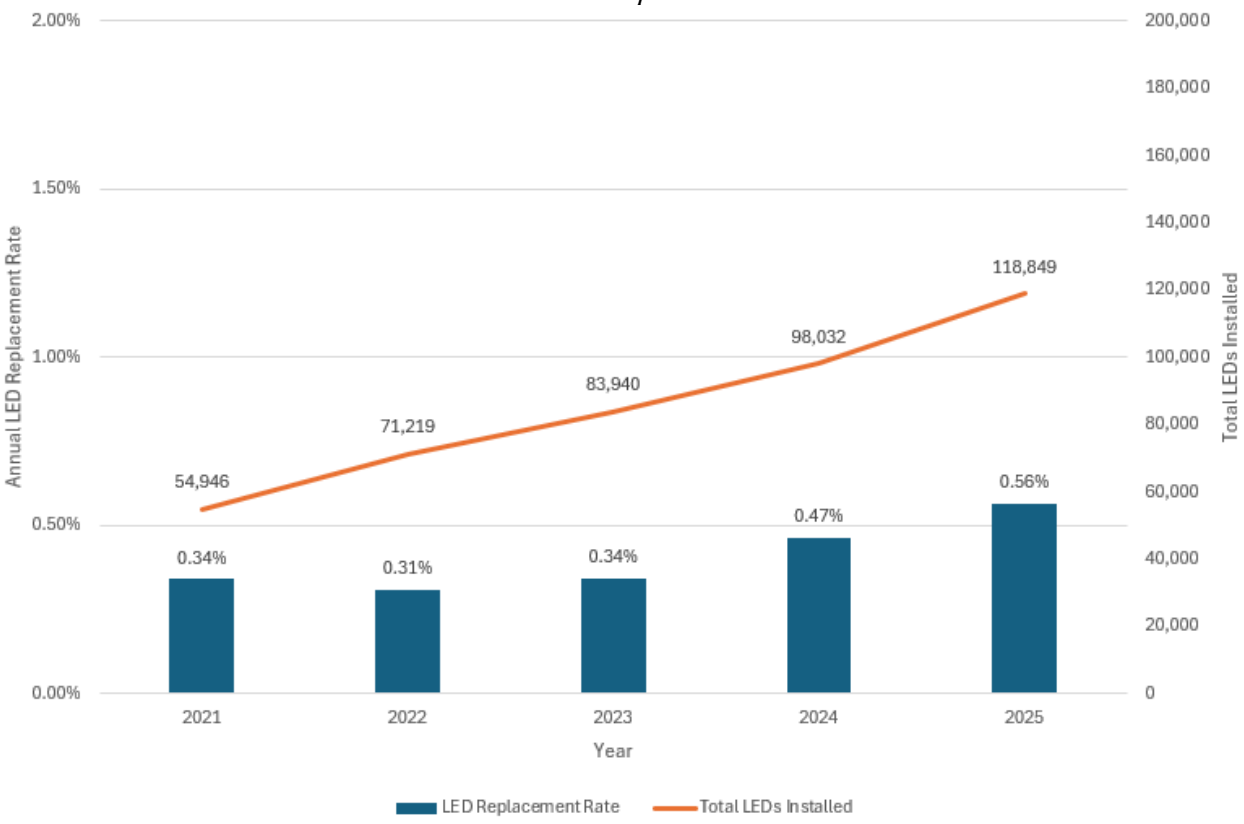
Q. What are the causes or contributing factors for the 27% increase in post top replacement orders in 2024?

A. The increase in post top replacement orders in 2024 is a result of LED conversion upon first failure mode of post top fixtures. Historically, if an HPS bulb was burnt out, the bulb would be replaced, not the entire fixture. This would result in a "Bulb Replacement" category order. As shown in Figure 3, post top replacement orders increased slightly in 2025 and bulb replacement orders decreased. This reflects continuation of LED conversion upon first failure mode of post top fixtures.

Q. What is the historical LED replacement rate?

A. Historical LED replacement data is shown below in Figure 4. LEDs are very reliable with a less than 0.6% replacement rate.

Figure 4
Historical LED Replacement Data



Q. Can the Company determine whether the LED luminaires it installs are defective without tracking outages by luminaire type?

A. Yes, the Company can determine whether LED luminaires are defective without tracking outages by luminaire type.

For product changes, the Company uses the First Part Approval process to validate the material changeover from HID to LED fixtures. This ensures the product meets standards and specifications.

For LED lighting defects (product non-conformances) identified by the field, the field team notifies the Supplier Quality Department; the Supplier Quality Department documents the quality issue and determines whether it is a non-conformance, the Company notifies the supplier of the defect, and the Company determines corrective actions. Street lighting non-conformances are documented in the Company's quality management software to record corrective and preventative actions required to prevent recurrence. Supplier Quality implemented tracking of product non-conformances in the Company's quality management software in 2022.

Q. Were there any streetlighting product non-conformances that required the removal and replacement of field installed equipment in 2025?

A. Yes. During 2025 the Company observed an elevated photo controller failure rate that impacted both HID and LED luminaires. The Company replaced LED luminaires if a photo controller failed. The Company tracked photo controller defect rates, and determined this was an isolated issue that had been resolved. Elevated photo controller defects were a result of a capacitor issue during a manufacturing period from late 2019 and early 2020. All controllers with manufacturing dates before and after the defect period have been confirmed as operating acceptably by the manufacturer. 724 photo controllers were replaced in 2025 (293 of them on HPS fixtures), resulting in 1 LED being replaced due to a failed photo controller.

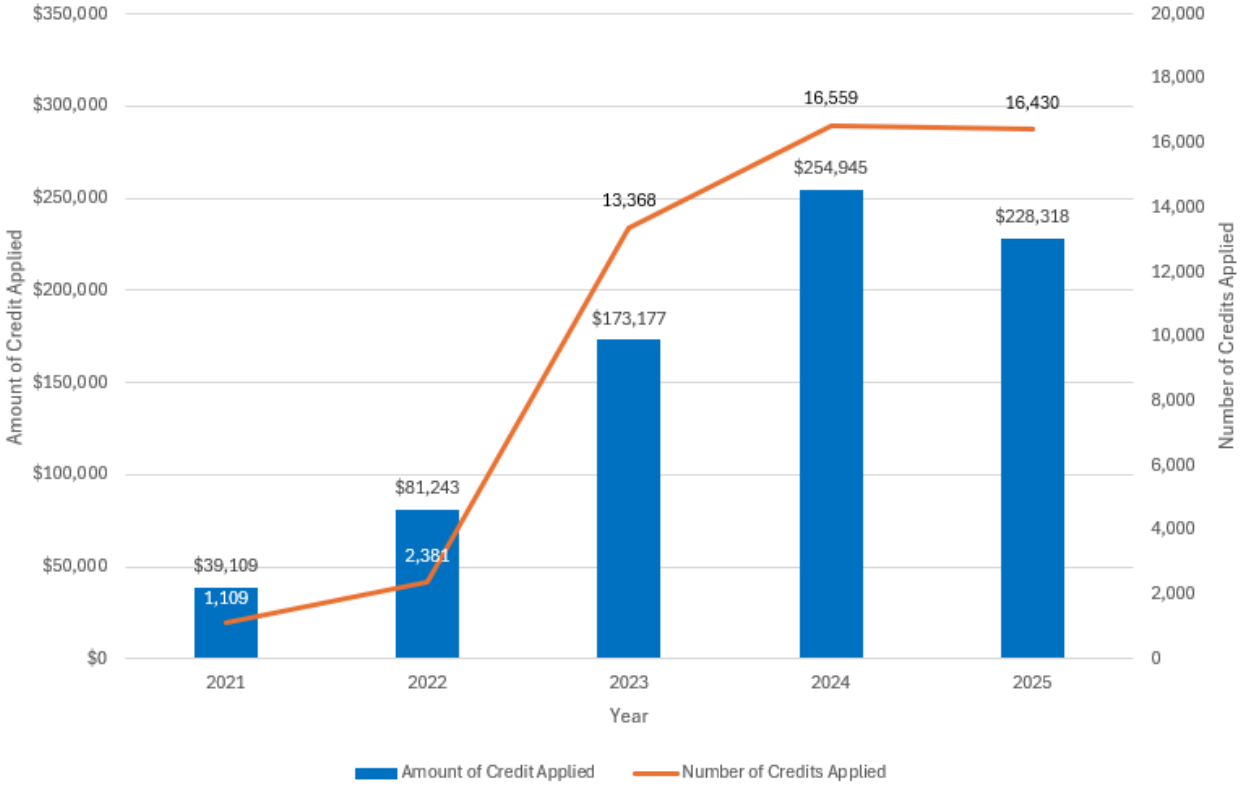
The Company is utilizing its First Part Approval process to identify an additional supplier of photo controllers. LED luminaires that were replaced due to a failed photo controller are reflected in Figure 4.

Q. Does the Company provide credits to customers for streetlight outages?

A. Yes. Pursuant to the Company's current streetlight tariffs, the Company provides a pro-rated bill credit calculated from the date a streetlight outage is reported and continuing until the light is returned to service. The streetlight outage credit is issued within 90-days of the streetlight returning to service.

The Company provides an outage credit for each and every streetlight outage. However, the number of outage credits applied does not always equal the number of actual outages; outage credits by customer may reflect multiple outages for the same type of light. For example, if a customer has five 40-watt streetlight outages within a billing period, one credit would be applied for the total amount of the credits for all five lights. Historical streetlight outage credit data is shown in Figure 5 below.

Figure 5
Historical Streetlight Outage Credit Data



The increase in the number of outage credits applied between 2022 and 2025 is a direct result of the methodology for application of outage credits for all streetlight outages, regardless of duration (MPSC Case No. U-21203).

Q. Are there circumstances in which longer duration outages are unavoidable?

A. Yes. In certain circumstances, the ability to safely and timely restore a streetlight can be difficult. Streetlight knockdowns, underground cable faults, requirements for traffic control, and replacement of special-order materials can sometimes lead to longer duration streetlight outages.

Q. Does the Company monitor longer duration outages and their status?

A. Yes. All streetlight outages greater than 60 days are discussed in weekly workplan meetings. The Company's target is no more than 125 streetlight outages statewide exceeding 60 days in duration, with no more than 25 of those exceeding 125 days in duration.

Q. What was the Company's performance in 2025 regarding outages exceeding 60 days?

A. The Company started 2025 with a backlog of 444 streetlight outages exceeding 60 days. The Company ended 2025 with 54 streetlight outages exceeding 60 days.

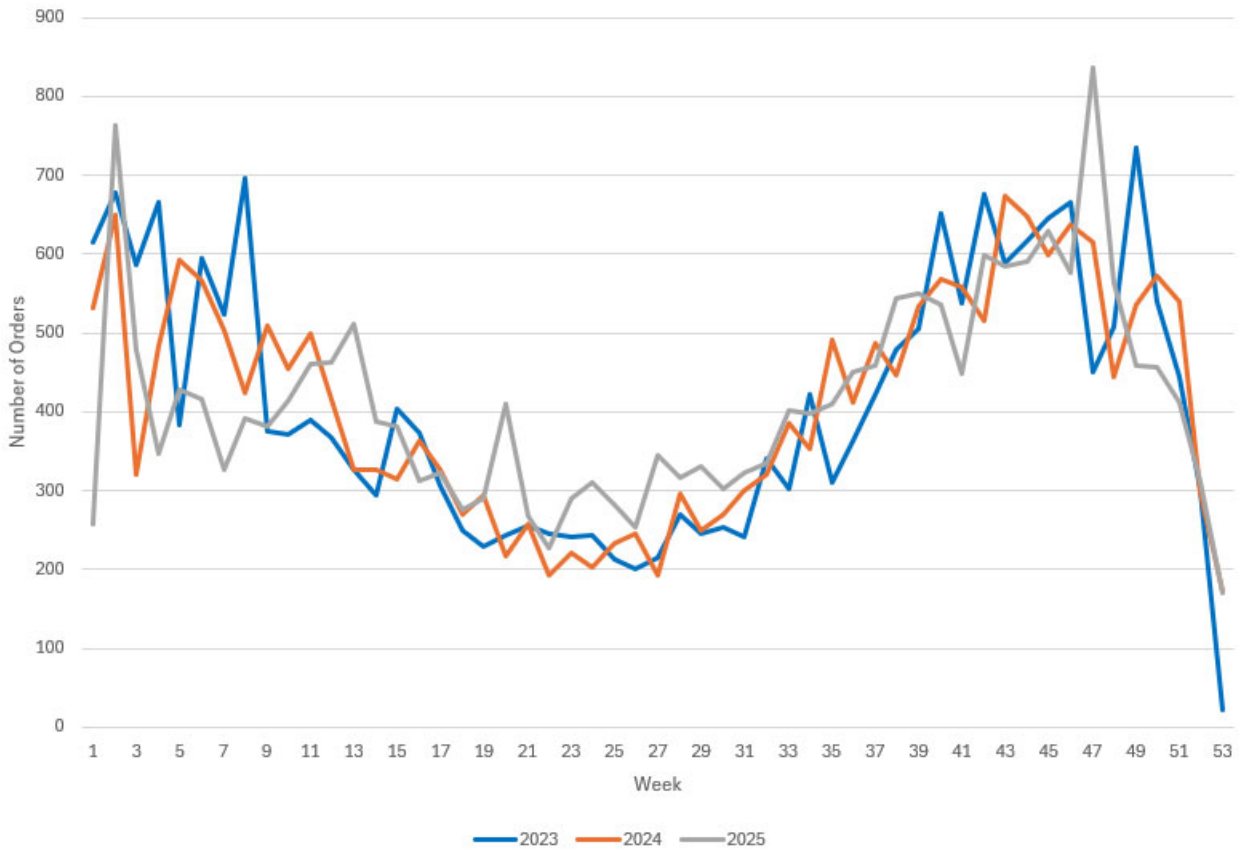
Q. Are longer duration outages localized, or do they occur through Consumers Energy's service territory?

A. Longer duration outages generally occur throughout Consumers Energy's service territory proportionate to the geographic dispersion of streetlights.

Q. Has the Company made any decisions regarding the future performance of streetlight outage restoration work?

A. Yes. Based upon variability of outages reported throughout 2023, 2024, and 2025, the Company has determined it will continue to employ a blend of Company resources and contractors to complete streetlight outage restoration work and vicinity upgrades. This resource strategy will allow the Company to flex its contracted resources to meet changing streetlight outage restoration demand. Figure 6 below represents differing levels of incidents reported throughout the year, driving the need for a blended workforce.

Figure 6
Weekly Streetlight Order Count



Q. What other actions has the Company taken to improve streetlight outage restoration performance?

A. In addition to the implementation of cobrahead and post top vicinity upgrades, the Company completed a patrol and fix initiative (November 2021 through March 2022), completed an advanced lighting controls initiative in October 2022, solicited feedback from internal and external stakeholders regarding its SOAR application, completed one SOAR application upgrade, and is underway with the second SOAR application upgrade (including user-generated reliability reports), completed evaluation of advanced lighting control implementation, and discussesits long-term reliability plan in the Company's revised Reliability Roadmap. The Company has also implemented internal prioritization standards for restoration of outages greater than 60 days. With the exception of cobrahead and post top vicinity upgrades, the Company is not seeking to recover any investment in these initiatives.

Q. What were the results of the patrol and fix initiative?

A. The patrol and fix initiative was in place between November 2021 and April 2022 in the Adrian and Kalamazoo service territories, and in place mid-February 2022 through March 2022 in the Muskegon service territory. In total, nine cobrahead fixtures in Adrian, one cobrahead fixture in Kalamazoo, and six cobrahead fixtures in Muskegon were identified as failed and repaired upon identification.

Q. Does the Company intend on reinstating its patrol and fix initiative during the bridge period or test year?

A. Not at this time. From January 1, 2022 through March 31, 2022, 1,499 streetlight outages were reported by customers in the Adrian, Kalamazoo, and Muskegon service territories.

Time spent searching for 16 outages that weren't reported is time that could have been spent repairing identified outages. The quantity of outages reported by customers is indicative of their adoption of the Company's reporting technology and its effectiveness relative to the patrol and fix initiative.

Q. What were the results of the advanced lighting controls initiative?

A. 204 total smart nodes were installed statewide (Flint, Jackson, Leelanau, Kalamazoo, Muskegon, and Marshall Training Center). The data collection period was October 1, 2022, through October 31, 2022. Ten smart nodes of each manufacturer were installed at each location (except Marshall Training Center). Evaluation criteria included: status of light visibility, identification of fault information, accurate metering of power usage, and energy savings provided for the customer.

Capabilities observed: manually turning streetlights on/off, manual dimming of streetlights, creation of scheduled dimming events, outage reporting of streetlights, and status communication of streetlights.

Q. Does the Company intend on reinstating the advanced lighting controls initiative in the bridge period or projected test year?

A. Not at this time. The Company completed an internal review of the initiative to determine the viability of technology implementation. The Company also surveyed participating municipalities in the first quarter of 2023 to collect feedback regarding features they like to use, software package preference, and overall customer sentiment for installation of advanced lighting controls. A formal business case will be prepared, and a summary of the results will be submitted for approval in a future electric rate case prior to any implementation. The 204 smart nodes remain in-service, and the Company continues to

partner with the initiative participants to identify use cases and to define functional requirements for broader installation.

Advanced lighting controls provide features and functions that some municipalities may find beneficial, while some municipalities may find the expense outweighs these benefits. The Company will continue to gauge interest from its street lighting customers and evaluate project feasibility through established business planning processes.

Q. What were the results of the Company's internal review of the advanced lighting controls initiative?

A. Feedback from municipalities included not using all the product functionality, concern over internal cost to maintain, and concern over cost of implementation. Estimated O&M savings (reduced truck rolls) were less than anticipated costs associated with maintaining the devices in the field and managing the digital experience (manage software program, integration with existing software (SAP, SOAR, etc.), coordination with manufacturer and municipalities, and maintenance of the new rate and tariff).

The Company has decided to pause implementation of advanced lighting controls based on the cost of the technology, lack of customer interest, and minimal O&M savings.

Q. When did the Company begin converting HID post top streetlights to LED?

A. The Company began converting HID post top streetlights to LED in January 2024.

Q. Why does the Company convert HID post top streetlights to LED?

A. Post top streetlights represent the second largest quantity of HID streetlights the Company operates and maintains (approximately 43,000). Post top streetlights are typically unique, meaning other manufacturers do not produce the same exact streetlight. The Company's

HPS luminaire suppliers have indicated HPS post top streetlights have been discontinued mainly due to low demand amidst a higher demand for LED luminaires.

Implementing a post top reactive conversion program, similar to that already in place for cobrahead luminaires, results in similar customer benefits (reduced energy use, no upfront cost, etc.,).

Q. Why did the Company recommend implementing vicinity conversions for HID post top streetlights?

A. Customer feedback received during HID cobrahead conversions indicate customers are sensitive to variation in lighting temperature (color). This sentiment was expected to be amplified in post top lighting applications, where lights are typically installed for beautification and the light temperature variation may not be aesthetically appealing. Vicinity conversion of HID post top lights reduces appearance of lighting temperature differences, leading to sustained or increased customer satisfaction, and improved reliability. Preliminary analysis of HID post top streetlight vicinity conversions indicated savings and improved reliability of service for street lighting customers.

Q. How did the Company evaluate vicinity conversions for HID post top streetlights?

A. The Company analyzed savings from 2022 when completing vicinity conversions on cobrahead streetlights. Vicinity conversions reduce the unit cost per conversion by reducing frequency of repair worker mobilization to the same area. Table 6 below illustrates the difference between a reactive conversion and a vicinity conversion.

The Company's current workplan reflects an assumption of 7,010 HID post top to LED conversions per year (1,100 vicinity conversions) starting in 2026. This equates to customer savings of $136,400 per year versus exclusively reactive conversion.

Q. What is SOAR and what is it intended to provide?

A. SOAR is a web-based application that allows customers to self-report streetlight outages. SOAR was implemented to increase customer satisfaction through self-service capabilities, reduce information technology related costs, reduce incoming call volume for contact centers, and improve the process for handling streetlight outages.

Q. When did the Company begin using the SOAR application?

A. The Company launched the SOAR application in 2021.

Q. Please describe the benefits of the SOAR application.

A. The SOAR application benefits customers in a variety of ways. Specifically, the SOAR application project deployed an accurate self-service streetlight outage notification program for use by customers, providing accurate streetlight outage identification and more rapid restoration resolution. Additionally, the project defined appropriate repair manifests and global positioning system ("GPS") locations to ensure deployed repair crews have the correct equipment and location. The project also provided customers with the capability to immediately identify the status of the repair online and avoid the need to contact Customer Service. Figure 7 below demonstrates streetlight information for a user-selected streetlight with the option to report an outage in SOAR. Figure 8 below shows in-service, in-progress, and extended repair streetlights on the SOAR map. Figure 9 below shows the status of the repair. Blue lights are operational, orange lights are reported as outages.

Figure 7
SOAR Screenshot: Streetlight Information

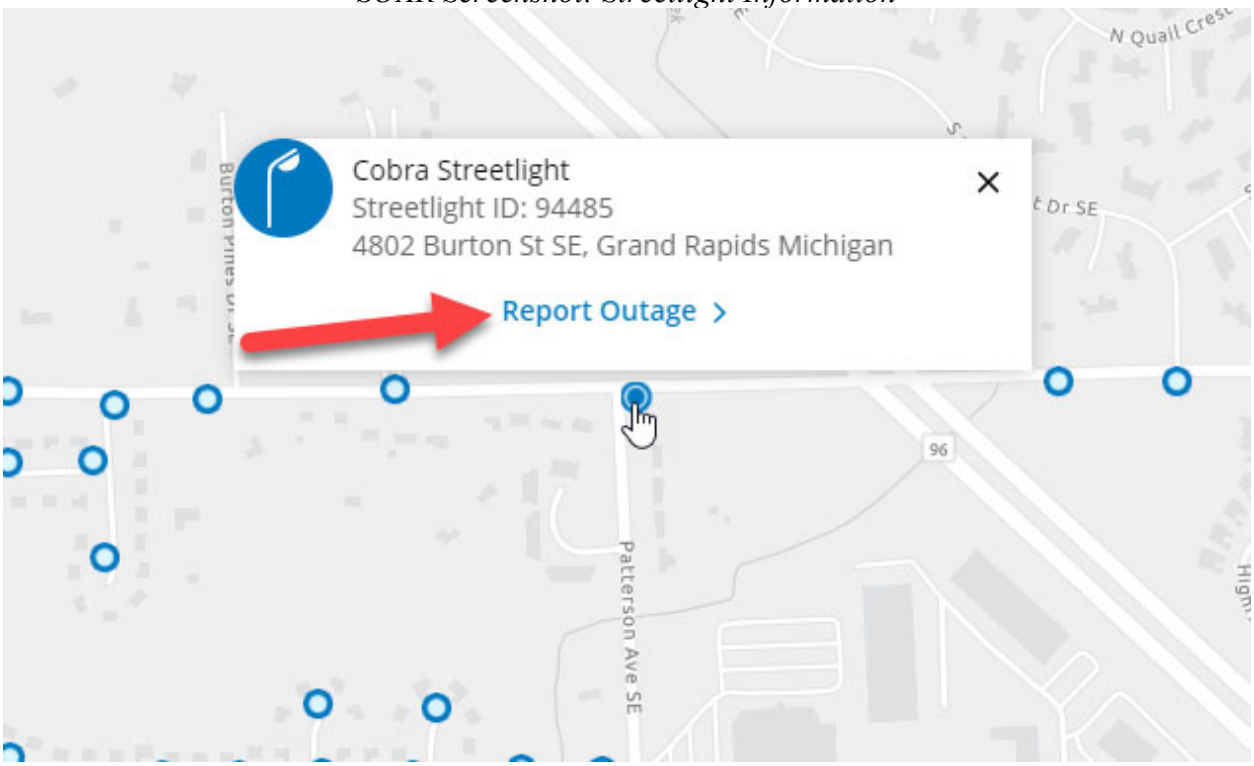


Figure 8
SOAR Screenshot: Streetlight Status on SOAR Map

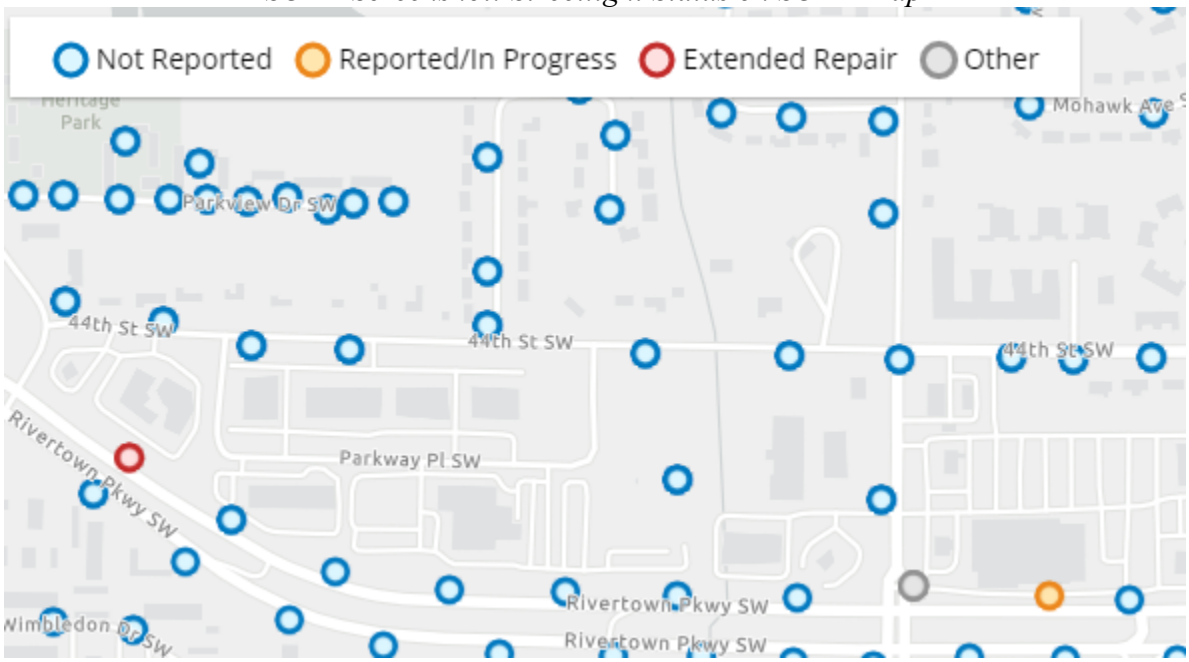
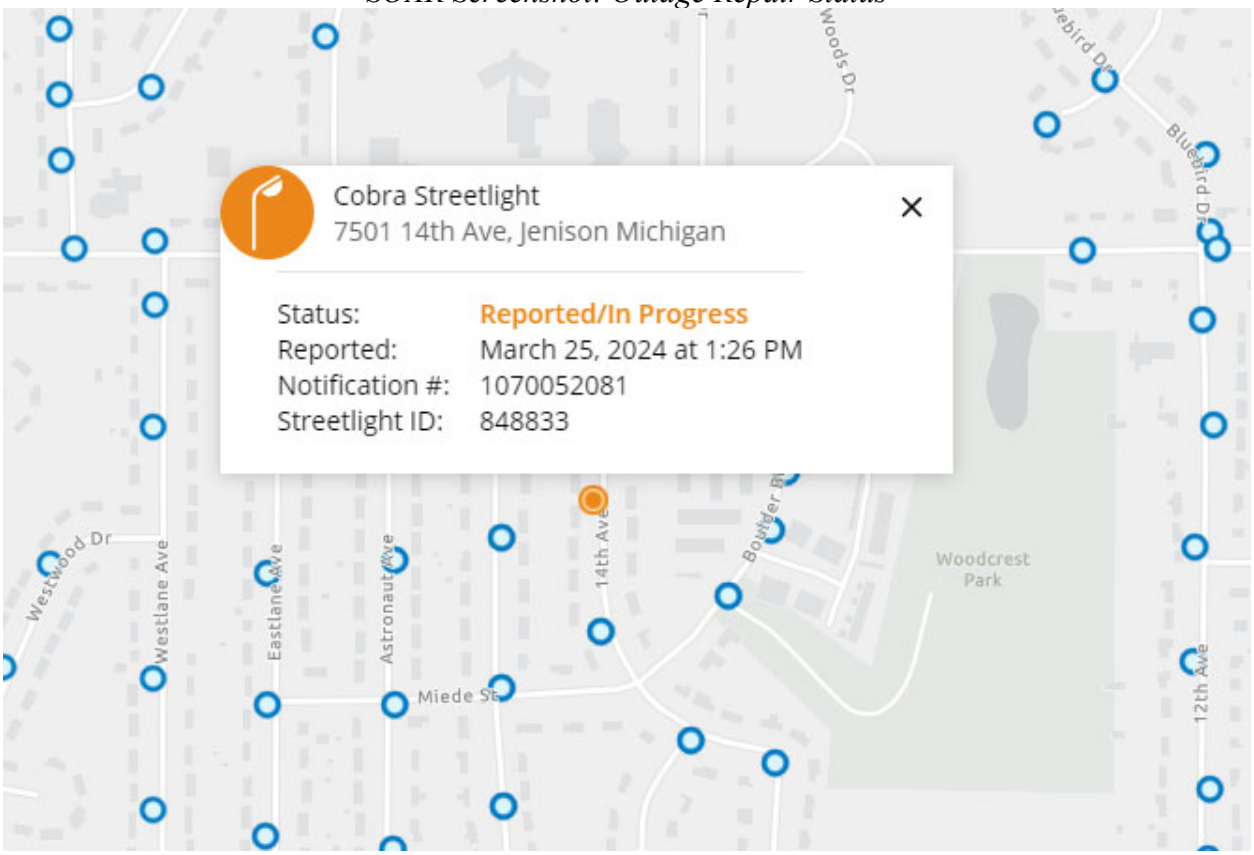


Figure 9
SOAR Screenshot: Outage Repair Status



Q. Does the SOAR application provide economic benefits in addition to the qualitative benefits previously described?

A. Yes. The SOAR application provides cost reductions in several ways. First, the SOAR application is projected to reduce customer calls, resulting in annual savings of $38,500, improved public safety and customer satisfaction. Second, the SOAR application will eliminate duplicate reported outages, resulting in projected annual savings of $1.5 million due to the elimination of duplicate truck rolls (nearly 14% of the 20,419 streetlights reported in 2019 were duplicate orders). In addition to the projected cost reductions for the call center and field services, the SOAR application is projected to reduce annual Information Technology ("IT") support costs by $60,000 as a result of consolidating streetlight portal components into the core customer facing portal.

Q. Where are these economic benefits accounted?

A. The economic benefits have already been incorporated into the unit cost of the work the Company expects to conduct.

Q. Has the Company created a standard reliability report for streetlighting performance?

A. Pursuant to Case No. U-21389, the Company, MI-MAUI, and MPSC staff worked together to identify metrics to include in reliability reporting. The Company presented its plan to MPSC staff regarding including self-service reliability reporting from the SOAR application on June 5, 2024. The self-service reporting was included in Case No. U-21585. Self-service reliability reporting is scheduled to go live in June of 2026.

Q. Do you have any final thoughts regarding the Company's outage identification and restoration process?

A. Yes. As I have already discussed, the Company has evaluated and continues to evaluate a number of different customer streetlighting service concerns, and will use continuous improvement methods to identify and implement process improvements where applicable. The Company has completed its patrol and fix, and advanced lighting control initiatives. The Company is now converting HID post top, center suspension, and cobrahead fixtures to LED technology upon failure. Streetlighting reliability is further advanced through the execution of vicinity conversions for both cobrahead and post top luminaires. Additionally, the Company has augmented its own field resources with contracted resources, and is continuing to engage customers regarding advanced lighting control installations. The Company will continue to collaborate with its streetlight customers, MI-MAUI, and other interested stakeholders in the future, as demonstrated by its

participation in the working group resulting from DTE's order in Case No. U-21534 to continue to improve the streetlighting service that it provides to its customers.

IV. LED STREETLIGHT EQUIVALENCY EVALUATIONS AND NEW BUSINESS

Q. Please describe the Company's process to evaluate the equivalency of replacement LED lighting.

A. The Company relies on technical standards to help ensure the proper amount of illumination is provided to roadways. The Company's primary focus in selecting replacement LED lighting is the actual equivalency of the selected alternative to ensure roadways are properly illuminated for safety while controlling costs. There are multiple technical factors the Company evaluates to ensure equivalency, such as total light loss factor, which includes lamp lumen depreciation and dirt depreciation, and roadway and pedestrian activity classifications. Considerations such as the specific location of the existing lighting relative to the roadway it is intended to illuminate are also important. I will discuss additional standards the Company considers in its equivalency evaluations later in this testimony.

Q. What is the origin of the Company's equivalency standards?

A. In 2014 and 2015, the Company worked closely with a lighting consultant to not only develop its LED specification, but also developed a method by which the Company could verify the LEDs submitted for consideration are equivalent to the luminaires they are intended to replace. The method the Company uses ensures the selected LED luminaire will adequately provide equivalent roadway illumination.

Q. Please specify what roadway lighting standard(s), if any, the Company follows?

A. The Company uses ANSI/IUES RP-8-22 Recommended Practice for Lighting Roadway and Parking Facilities.

Q. Please explain what luminaire performance factors the Company evaluates for equivalency. Please address specifically, but not exclusively, lumens, light distribution patterns, Backlight-Uplight-Glare ratings, Correlated Color Temperature, and Color Rendering Index.

A. For equivalency, the Company uses Agi32 software to verify optimized span lengths based on roadway classification and pedestrian activity to determine equivalency compared to the span lengths of existing HPS cobrahead fixtures. The performance factors listed in the question are used to determine conformance to the Company's specifications but not equivalency.

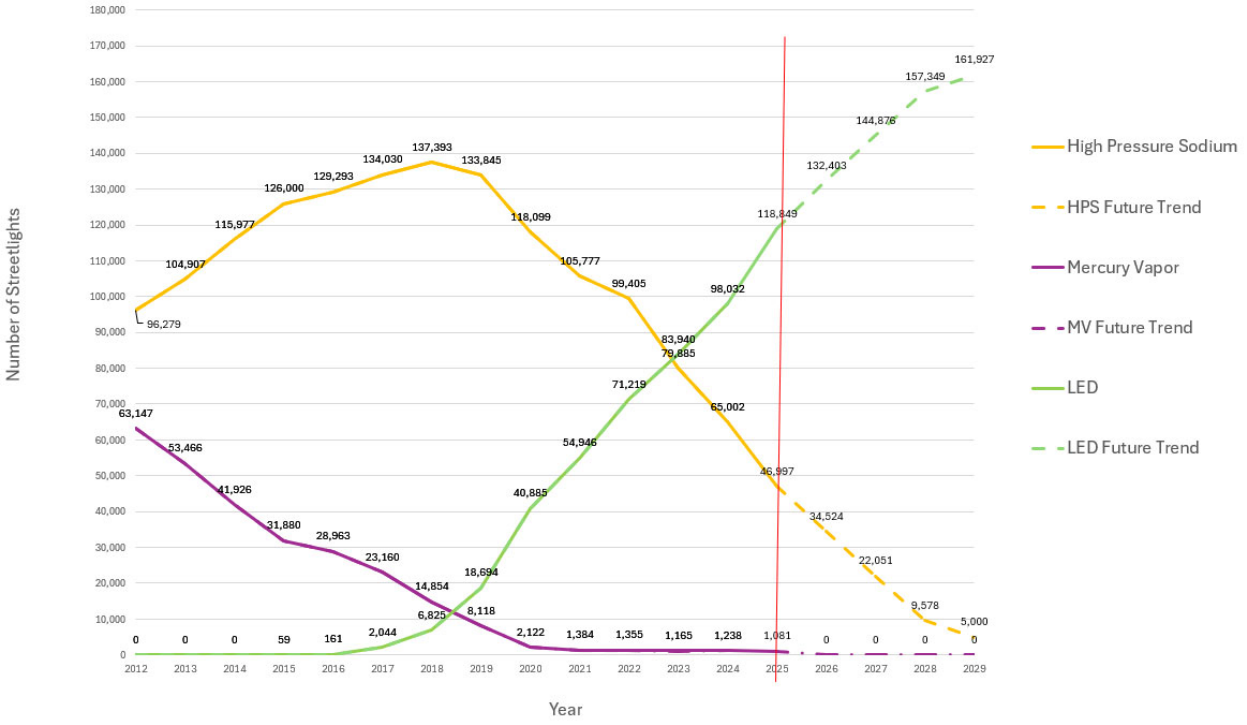
Q. How often does the Company competitively evaluate replacement lighting?

A. The Company typically issues competitive solicitations every three years, with the Company's most recent competitive solicitation completed in January 2025. As part of the most recent solicitation, the Company evaluated the latest equivalent LEDs submitted by multiple manufacturers. Streetlight technology, like many other technologies, changes and improves frequently. However, it would be unreasonable to evaluate the changing technology more frequently than every three years.

Q. How have technology trends impacted installations?

A. See Figure 10 below for historical and projected lighting technology installed (Figure 10 does not include lights that are billed as Outdoor Commercial or Outdoor Industrial).

Figure 10
Streetlight Technology Trend



Q. For each HID cobrahead, post-top, or center suspension wattage and type (HPS, MV, MH) of which the Company had more than 3,000 deployed at the end of 2023, please provide the standard (or most common) LED equivalent wattage used before and after the 2025 competitive solicitation.

A. Pre- and post-2025 competitive solicitation LED equivalent wattages are shown in Table 1 below.

Table 1
LED Equivalent Wattages

Fixture Type	LED Wattage Prior to 2025 Bid	LED Wattage post 2025 Bid
Cobra	40W	30W
Cobra	70W	60W
Cobra	80W	70W
Cobra	150W	140W
Center Suspension	40W	40W
Center Suspension	70W	70W
Traditional Non-Cutoff Post Top	50W	50W

Q. Why doesn't the Company competitively solicit replacement lighting more frequently?

A. The effort to replace its existing LED lighting portfolio is not a small undertaking. Considerations such as depletion of existing inventory, satisfaction of existing lighting contracts, and complete evaluation of alternative lighting products is a considerable effort. The establishment of lighting contracts that have a minimum term of three years results in better unit pricing from manufacturers in comparison to contracts for only one or two years, which would have smaller contract values. It would be unreasonably expensive to engage in a competitive solicitation process annually. This would effectively result in the need for additional resources, both engineering and supply chain, with little or no economic benefit. Although manufacturers continuously improve their lighting products, the Company must make strategic decisions as to how frequently it can transition from its current lighting products to new lighting products.

Q. How does the Company evaluate alternative LED lighting products to ensure equivalency?

A. The Company begins its evaluation of alternative LED lighting products by ensuring the wattage of the replacement LED luminaire is equal to or less than the wattage of the

luminaire it will replace, to ensure the replacement product's monthly rate is the same or less expensive than the existing luminaire, all else being equal. The next step in the equivalency process is to consider the specific roadway application, including roadway classification, pedestrian activity, pavement class, roadway width, location, and mounting height to ensure the average luminance, average and maximum uniformity, and the maximum veiling luminance (disability glare) is in accordance with industry guidelines. The next consideration for the evaluation is to perform a financial analysis among replacement equivalent products for impacts to the customer as well as the Company. The final consideration for the evaluation of equivalent lighting products is the aesthetics of the replacement luminaire.

Q. Does the Company's equivalency evaluation process ensure that replacement LED lighting meets DesignLights Consortium ("DLC") Qualified Products List criteria?

A. Yes. This criteria was included in the Company's most recent competitive solicitation for LED lighting products. In addition, all LED cobrahead luminaires previously selected in the Company's competitive solicitations since 2018 also met this criteria.

Q. Please explain why DLC certification is important.

A. DLC is a group that certifies light output used in energy rebates around the world. This group independently certifies the quality and performance of lights. DLC essentially ensures luminaires meet their advertised specifications for lumen output, color rendering index, color temperature, total harmonic distortion, power factor, etc. Selection of a DLC-certified light helps ensure you receive a quality product.

Q. Does the Company only utilize the equivalency evaluation process to support lighting conversions?

A. No. The Company also leverages the technical characteristics of the newly selected lighting to support lighting designs for new streetlight installations. The Company receives customer requests for installation of new streetlighting (*i.e.,* new subdivisions) and leverages the results of the LED lighting evaluations to design the new lighting.

The capital expenditures associated with new streetlighting are reflected in Exhibit A-12 (DAS-1), Schedule B-5.10, page 1, line 1.

Q. Does the Company utilize the LED fixtures for purposes other than existing light conversion?

A. Yes. The Company uses the LED cobrahead and post top fixtures in new business applications as well. Projected new business expenditures are summarized in Table 2 below.

Table 2
Projected New Business Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2027)	$4.797 million	285
Test Year (ending 4/30/2028)	$3.692 million	214

Q. How did the Company develop the projected capital expenditures for streetlighting new business?

A. The Company calculated the five-year historical average capital expenditure amount for the period from 2021 through 2025 and escalated that amount by an inflation rate of 2.9% for 2026, 2.5% for 2027, and 0.7% for 2028. The number of new business streetlights and their unit costs are presented in Exhibit A-12 (DAS-1), Schedule B-5.10, page 2, lines 1 and 2.

Q. Is unit cost analysis appropriate for comparing projected capital expenditures for streetlighting new business?

A. No. Unit cost is not an appropriate basis for evaluating streetlighting new business expenditures due to the potential difference in cost associated with materials, construction means and methods, and size of the job proposed by the customer.

Q. Does the Company propose any changes to the streetlighting new business tariff(s)?

A. Yes. The Company proposes closing the GUL tariff to new business. Company witness Gray sponsors the revised GUL lighting rate tariff.

Q. Why does the Company propose closing the GUL tariff to new business?

A. The Company proposes closing the GUL tariff to new business because incandescent, fluorescent, mercury vapor, and HPS luminaires are no longer offered by material vendors.

V. CONVERSION OF COBRAHEAD, POST TOP, AND CENTER SUSPENSION STREETLIGHTS

Q. Do customers receive a rate reduction for HID lights that are converted to LED technology.

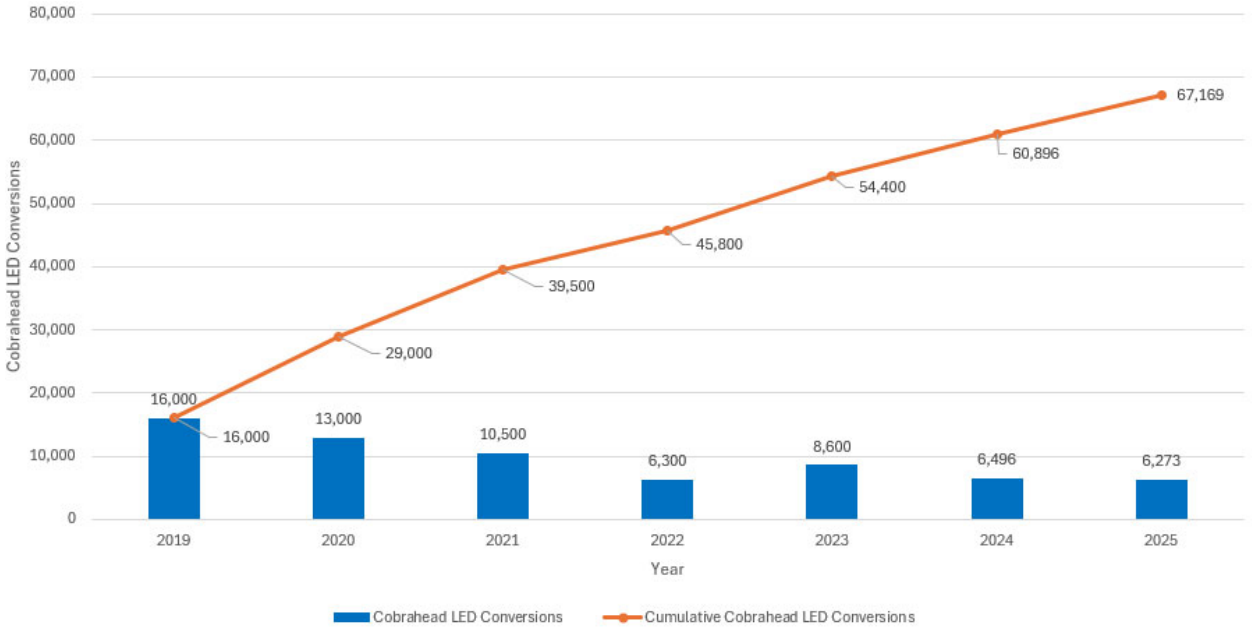
A. Yes. Depending on the luminaire type (post top, cobrahead, or center suspension), customers see between a $4.81 and $6.19 reduction in their lighting bill per month, per light converted. This rate reduction is attributed to the lower energy usage of the light. For example, a 100 Watt HPS cobrahead (currently billed at 115-124 Watts, including ballast) is $16.87 per month. Cobrahead lights are converted to 30 Watt LEDs (billed at 25-34 Watts). 30 Watt LEDs are billed at $10.68 per month. A 100 Watt HPS post top (currently billed at 115-124 Watts, including ballast) is $16.87 per month. Post top lights are

converted to 50 Watt LEDs (billed at 45-54 Watts). 50 Watt LEDs are billed at $12.06 per month.

Q. Please describe the Company's project to convert cobrahead streetlights from HID to LED.

A. Beginning in fall 2018, the Company made the decision to reactively convert all failed cobrahead streetlights from HID to LED as previously discussed in my testimony. Figure 11 below shows annual cobrahead LED conversions.

Figure 11
Annual Cobrahead LED Conversions



These reactive conversions are in addition to the MV conversions discussed later in this testimony. The Company expects that it will convert the remaining HID cobrahead fixtures by mid-2031.

Q. Why would the Company expect that all of its HID cobrahead fixtures would fail by mid-2031?

A. The lamps on the HID fixtures are rated for 24,000 hours of service. With approximately 4,200 hours of lighting service annually, the average life of the lamps is approximately six years.

Based on observed cobrahead failure data (included in Figure 11), the Company is projecting 5,500 cobrahead failures per year that will be converted to LED technology.

Q. How is the projected streetlighting expenditure level aligned with the revised Reliability Roadmap?

A. As described in the revised Reliability Roadmap (Exhibit A-95 (EMD-11)), these expenditures are essential to extend the lifecycle of luminaires and reduce repair expenses across the Company's streetlight portfolio. Vicinity conversions of cobrahead and post top luminaires prior to failure increases the efficiency of field personnel to reduce the cost of conversions and, effectively eliminates near-term outages.

Q. Is the Company proposing a change to the cobrahead vicinity conversion program?

A. No. The Company will continue to convert HID cobrahead fixtures in the vicinity of failed cobrahead fixtures. The Company will execute cobrahead and post top vicinity conversions based on failure location and regional workload. For estimating purposes, the Company assumed 260 cobrahead vicinity conversions per year, recognizing outage restoration is of higher priority than a conversion of a luminaire that has not failed.

The Company has performed an evaluation of three cobrahead conversion options: reactive, planned, and lights in the vicinity. A summary of the projected unit costs associated with each option is shown in Table 3 below.

Table 3
Cobrahead Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
$658.00	$606.09	$533.42

The reactive conversions have the highest unit cost but are a necessity as the light has already failed and requires attention. The incremental cost to convert the failed light to LED is essentially the cost of a vicinity conversion as travel time to the light cannot be avoided.

Q. Are all of the currently installed LED fixtures a result of the Company's reactive conversion program?

A. No. The Company effectively completed its planned MV conversion program in 2020. In the last decade, the Company has reduced its quantity of MV luminaires from more than 63,000 luminaires to approximately 1,200 luminaires, all of which are center suspension streetlights that I will discuss later in this testimony. At the beginning of the MV conversion program, the MV luminaires were converted to HPS, however in recent years the MV luminaires have been converted to LED. The Company also installed customer requested new LED lights as well as any customer requested conversion of existing HID fixtures to LED. Figure 10 above represents the Company's historical progress and illustrative continued progress.

Q. What are the projected investments for all streetlight failures?

A. Projected streetlight failure expenditures are summarized in Table 4 below.

Table 4
Projected Streetlight Failure Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2027)	$22.005 million	27,509
Test Year (ending 4/30/2028)	$16.935 million	20,632

These projected quantities include all fixture types including cobrahead, center suspension, post top, and floodlights.

Q. How did the Company develop the projected capital expenditures for streetlighting demand failures?

A. The projected number of demand failures was based upon the number of capital streetlight demand failures for the period from 2021 through 2023. This figure was increased to include post top LED conversions. These figures were then multiplied by a projected unit cost for reactive conversion. The number of demand failure streetlights and their unit costs are presented on Exhibit A-12 (DAS-1), Schedule B-5.10, page 2, lines 5 and 6

Q. Is unit cost analysis appropriate for comparing projected capital expenditures for streetlighting failure?

A. No. Unit cost is not an appropriate basis for evaluating streetlighting failure expenditures due to the potential difference in cost associated with materials, construction means and methods, and the type of failure (luminaire, pole, conductor, etc.).

Q. Can you explain what you mean by planned and reactive conversions?

A. Yes. Planned conversions are performed on HID lighting that have not yet failed. The Company's reactive program, in contrast, will perform its HID to LED conversions on cobrahead fixtures, post top fixtures, and center suspension fixtures that have failed in service. The Company's standard practice since 2018 had been to only convert cobrahead fixtures upon failure; however, the Company extended that practice to center suspension

fixtures beginning in 2022, and post top fixtures in 2024. The preferred method for conversion of center suspension failures will be through the use of a direct replacement LED at failure, as discussed later in this testimony.

In addition, as previously discussed, the Company began to convert HID cobrahead fixtures in the vicinity of failed cobrahead fixtures in April 2022, and HID post top fixtures in the vicinity of failed post top fixtures in February 2025.

Q. Why did the Company originally choose to convert its cobrahead streetlights from HID to LED on a reactive basis versus a planned basis?

A. There were significant benefits to offering a reactive LED conversion program to address the concerns the Company has heard from a number of its streetlighting customers. The feedback the Company received from its customers was that they wanted to move to LED lighting versus the existing HID technology as quickly as possible. The Company also received feedback that many of its customers did not want to pay total project cost for the planned conversions or for conversions at all. Many municipal customers operate under very tight budget constraints and may not have the available resources to execute on a community-wide planned replacement of all their streetlights, which would require a significant up-front customer contribution. Replacing lights on a reactive basis means that customers do not require any up-front contribution.

Q. What were some of the other considerations with a reactive conversion approach?

A. With a service territory of approximately 28,000 square miles, and more than 800 streetlighting customers, a planned approach to converting streetlights would unnecessarily advantage certain customers over others. In addition, and as previously discussed, the rated life of the HID lamp is 24,000 hours and, as a result, the Company knew it would visit the

majority of HID cobrahead streetlights over seven years for lamp replacement and/or complete luminaire replacement. Since the Company already had to visit the light due to its operational status, it made sense to simply convert the light upon failure rather than make a separate trip to the light to convert on a planned basis. As a result, the Company made a decision to embark on a program to replace all HID cobrahead luminaires upon failure. This balanced approach was deemed to be fair and equitable because it provides each community with the benefit of LED lights at approximately the same conversion rate, absent an up-front cost to the customer. Therefore, the benefits and costs of the investment into streetlights is equally realized by all customers with this approach. In contrast, a Company-planned conversion with no up-front contribution would mean some communities are paying for others to realize the benefit of LED lighting while receiving no benefit themselves.

Q. Can you summarize the Company's selection of its reactive approach to cobrahead LED conversions?

A. Yes. Based upon the various factors that I have just discussed, including the cost comparison and the fact that the Company would already need to visit the majority of its HID cobrahead lights over five to six years since the inception of the program in 2018, the Company felt that its reactive conversion methodology upon failure provided a balanced approach to moving to LED streetlighting for all customers with no up-front contribution from customers. The Company's decision to also convert HID cobrahead lights in the vicinity of failed cobrahead streetlights is consistent with the intent of its original reactive conversion program and continues to be fair and balanced, will reduce the average cost per conversion, and will expedite the conversion process.

Q. Has the Company previously evaluated other cobrahead streetlight conversion models?

A. Yes. In addition to the replacement of cobrahead streetlights upon failure and the replacement of cobrahead streetlights in the vicinity of failed cobrahead streetlights, the Company also considered the conversion of cobrahead streetlights on a planned basis. Although the Company made the decision to go with its approach of replacing cobrahead streetlights upon failure as its preferred approach, customers who want to convert their cobrahead streetlights in a planned fashion still have that option as long as they pay for the upfront conversion costs.

Q. What is the Company's priority with respect to reactive cobrahead streetlight conversions?

A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires to restore lighting to its customers as quickly as possible, which customers have indicated they want and deserve, versus focusing resources on planned lighting conversions. The additional conversion of cobrahead fixtures in the vicinity of failed cobrahead fixtures will expedite the overall conversion process at a reduced cost, and will eliminate near-term outage events for these lights.

Q. Why does the Company convert post top streetlights from HID to LED?

A. Post top luminaire vendors began to phase out production of HID luminaires and components in 2021. By the end of 2023 all the Company's lighting vendors had completely discontinued HID post top product offerings. Because post top HPS product offerings are no longer an implementable solution, conversion to LED technology will

extend the lifecycle of the luminaire, and reduce the frequency of post top luminaire outages.

Q. Why has the Company chosen to convert its post top streetlights from HID to LED on a reactive basis versus a planned basis?

A. The reasons for choosing to reactively convert post top streetlights are similar to those that I previously discussed regarding reactive conversion of cobrahead streetlights. Replacing lights on a reactive basis is in line with customer feedback, and does not require any up-front contribution from customers.

Q. Why did the Company not move forward with conversion of its post top streetlights from HID to LED when it began reactive conversion of cobrahead streetlights to LED?

A. The Company did not move forward with the reactive conversion of post top streetlights at the same time as cobrahead streetlights because the Company recognized customers select post top streetlights based on aesthetics and style, unique to their application and location, and the Company wanted to evaluate and provide customers with the best LED post top lighting options. After careful consideration of the LED options and an understanding of what customers want, the Company chose two color options, amber (3000 Kelvin Temperature) and white (4000 Kelvin Temperature) for newly installed lighting requests and replacements of discontinued HID post top lighting. Lastly, cobrahead streetlights were the Company's largest lighting class, and are primarily supplied via overhead conductor. Post top streetlights represented a smaller percentage of the Company's streetlights and are supplied via underground conductor. Customer sentiment was favorable toward reactive conversion of cobrahead streetlights.

Q. What were some of the Company's other considerations with a reactive conversion approach for post top conversions?

A. The other considerations with a reactive conversion approach for post top conversions are similar to those I previously discussed regarding cobrahead conversions. A planned approach to converting streetlights would unnecessarily advantage certain customers over others. This balanced approach is fair and equitable because it provides each community with the benefit of LED lights at approximately the same conversion rate, absent an up-front cost. Therefore, the benefits and costs of the investment into streetlights is realized by all customers with this approach.

Q. Can you summarize the Company's selection of its reactive approach to post top LED conversions?

A. Yes. The Company's selection of its reactive approach to post top LED conversions is similar to its selection of its reactive approach to cobrahead LED conversions, which I have previously discussed. The Company has deemed that its reactive conversion methodology upon failure a balanced approach to moving to LED streetlighting for all customers with no up-front contribution from customers.

Q. Has the Company previously evaluated other post top streetlight conversion models?

A. Yes. In addition to the replacement of post top streetlights upon failure the Company also considered the conversion of post top streetlights on a planned basis. Although the Company made the decision to go with its approach of replacing post top streetlights upon failure as its preferred approach, customers who want to convert their post top streetlights in a planned fashion still have that option as long as they pay for the upfront conversion costs.

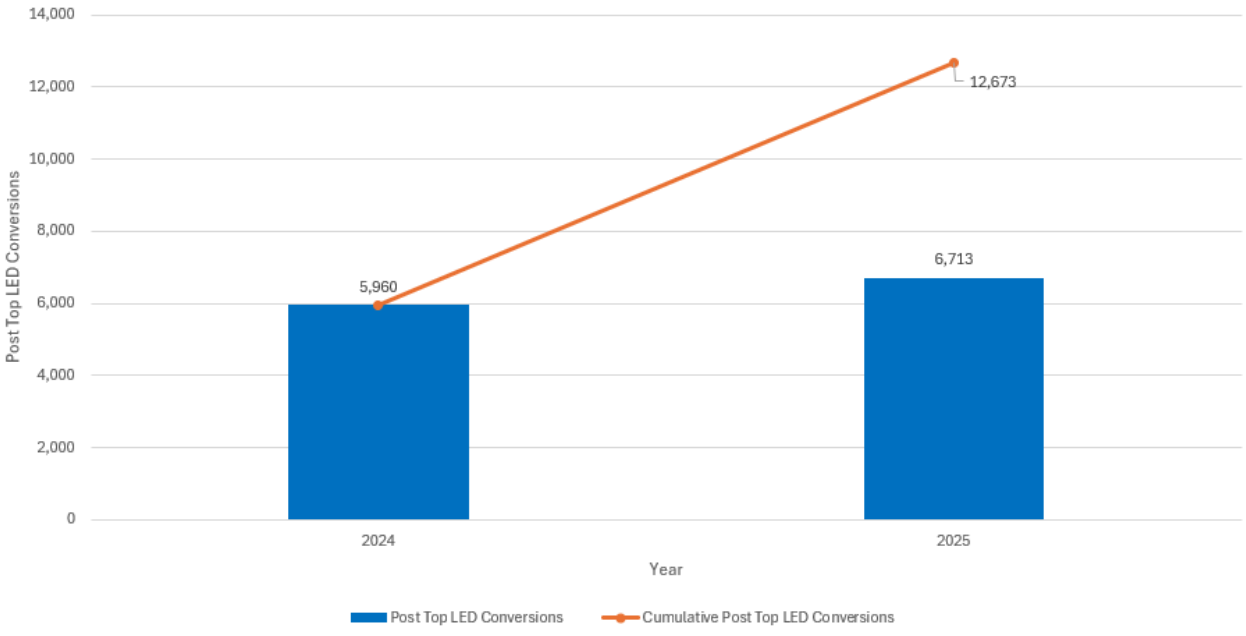
Q. What is the Company's priority with respect to reactive post top streetlight conversions?

A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires to restore lighting to its customers as quickly as possible, which customers have indicated they want and deserve, versus focusing resources on planned lighting conversions. Additional conversion of post top streetlight fixtures in the vicinity of failed post top fixtures will expedite the overall conversion process at a reduced cost and will eliminate near-term outage events for these lights.

Q. How many HID to LED post top conversions have occurred on an annual basis?

A. Figure 12 below shows annual HID to LED post top conversions.

Figure 12
Annual Post Top LED Conversions



Q. How is the Company addressing the failure of HID center suspension streetlights?

A. The Company has identified, evaluated, tested, and contracted for a direct replacement LED center suspension fixture that will accommodate most center suspension streetlight

locations. The Company will use the direct replacement LED center suspension fixture as its preferred replacement for center suspension streetlights. The Company expects it will convert the approximate 11,000 HID center suspension fixtures to LED over the next two to three years through its reactive replacement plan. Similar to the HID cobrahead fixtures, the HID lamps are rated for 24,000 hours of service and, as a result, should experience failure in five to six years based upon 4,200 hours of lighting service annually.

Q. What is the Company's strategy regarding use of direct replacement of center suspension streetlight fixtures?

A. Since 2022, the Company's preferred option has been the use of direct replacement center suspension streetlight fixtures because it is more economical and requires less intensive construction methods to install. Situations may exist that require the relocation of center suspension fixtures to the side of the road, however the Company will always attempt to use direct replacement center suspension fixtures upon failure.

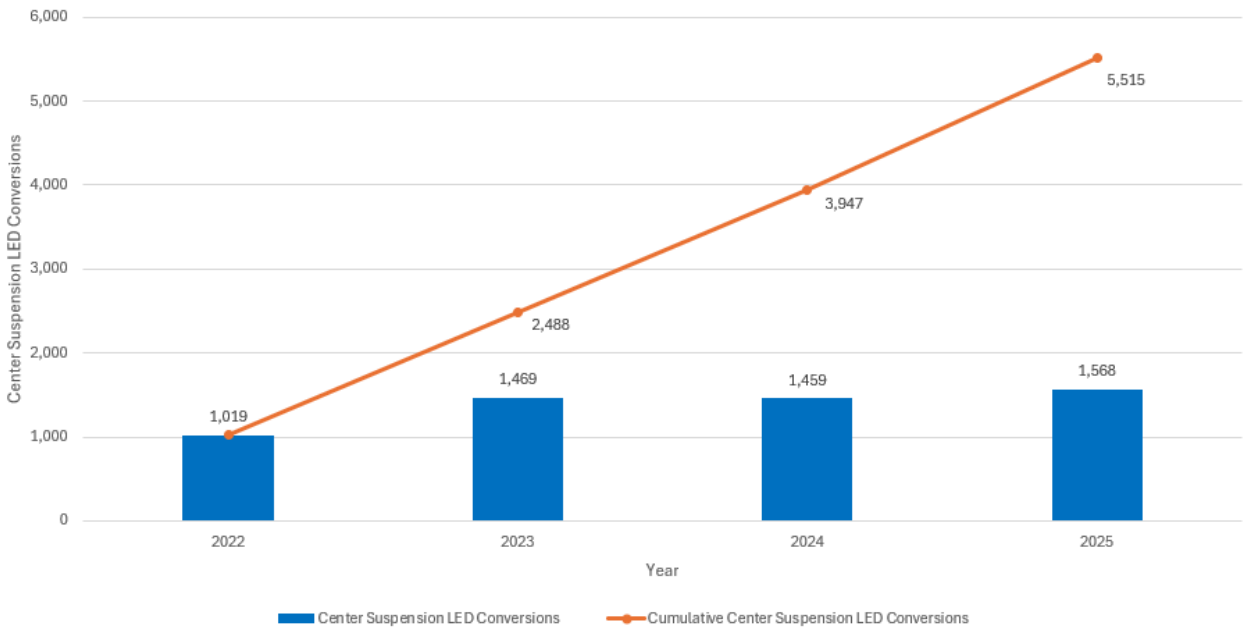
Q. What is the expected failure rate of the center suspension streetlights?

A. The Company expects center suspension streetlight failures to match the failure rate of cobrahead luminaires. With a total population of 11,000 center suspension installations across the state and an assumed 15% annual failure rate, the frequency of work in dangerous roadway situations is estimated at 1,650 lights annually.

Q. How many HID to LED center suspension conversions have occurred on an annual basis?

A. Figure 13 below shows annual HID to LED center suspension conversions.

Figure 13
Annual Center Suspension LED Conversions



VI. PLANNED STREETLIGHT CONVERSIONS

Q. Please describe the Company's planned conversions of cobrahead streetlights.

A. The Company will continue planned conversion of cobrahead streetlights located in the vicinity of failed cobrahead streetlights in 2026. The Company initiated planned conversions of cobrahead streetlights in April 2022. The planned conversion of cobrahead streetlights will leverage the fact that the crews have already traveled to the location of a failed cobrahead streetlight and, as a result, this will reduce truck rolls and indirect costs in the replacement of the additional cobrahead fixtures in the vicinity of the failed fixture.

Q. What is the expected reduction in truck rolls resulting from the conversion of lights in the vicinity of failed cobrahead streetlights?

A. As I will discuss later in this direct testimony, the Company is projecting it will convert 346 cobrahead streetlights in the 16-month projected bridge period ending April 30, 2027, and 260 cobrahead streetlights in the projected test year ending April 30, 2028, which are

located in the vicinity of failed cobrahead streetlights. Table 5 below summarizes vicinity conversion per year, by type. Because all of the cobrahead streetlight fixtures are expected to fail in the next two to three years due to lamp life, the Company will avoid a future truck roll for each cobrahead streetlight in the vicinity of a failed cobrahead streetlight. 346 truck rolls are expected to be reduced in the 16-month bridge period ending April 30, 2027, and 260 truck rolls are expected to be reduced in the projected test year ending April 30, 2028.

Q. How did the Company determine the projected number of cobrahead streetlights in the vicinity of failed cobrahead streetlights?

A. The Company considered the addition of post top vicinity conversions as well as historical vicinity conversions data.

Q. Please describe the Company's planned conversions of post top streetlights.

A. Based on increasing HID post top product obsolescence, the Company began to reactively convert post top streetlights in 2024 and execute planned conversions of post top streetlights in the vicinity of failed post top streetlights in 2025. The planned conversion of post top streetlights leverages the fact that crews have already traveled to the location of a failed post top streetlight and, as a result, this will reduce truck rolls and indirect costs in conducting the replacement of the post top fixtures in the vicinity of a failed fixture.

Q. Is the Company proposing a change to the post top vicinity conversion program?

A. Yes. The Company will continue to convert HID post top in the vicinity of failed post top fixtures. The Company will execute cobrahead and post top vicinity conversions based on failure location and regional workload. For estimating purposes, the Company will target 1,100 post top vicinity conversions per year, recognizing outage restoration is of higher

priority than a conversion of a luminaire that has not failed. This is an increase from 800 post top vicinity conversions targeted in 2025.

Q. What is the expected reduction in truck rolls resulting from the conversion of lights in the vicinity of failed post top streetlights?

A. As I will discuss later in this direct testimony, the Company is projecting it will convert 1,463 post top streetlights in the 16-month projected bridge period ending April 30, 2027, and 1,100 post top streetlights in the projected test year ending April 30, 2028, which are located in the vicinity of failed post top streetlights. Table 5 below summarizes vicinity conversion per year, by type. Because all of the post top streetlight fixtures are expected to fail within approximately seven years of the start of the program due to lamp life, the Company will avoid a future truck roll for each post top streetlight in the vicinity of a failed post top streetlight. 1,463 truck rolls are expected to be reduced in the 16-month bridge period ending April 30, 2027, and 1,100 truck rolls are expected to be reduced in the projected test year ending April 30, 2028.

Q. How did the Company determine the projected number of post top streetlights in the vicinity of failed post top streetlights?

A. The Company considered historical vicinity conversion data of cobrahead and post top streetlights.

Q. How did the Company develop the projected capital expenditures for vicinity conversions?

A. Based upon the projected material and labor costs, including loadings, the Company developed a projected cost per vicinity conversion of $533.42 for cobrahead lights and $781.42 for post top lights. This unit price essentially eliminates the cost of a truck roll

and travel time as compared to the unit cost for a reactive cobrahead conversion. Projected vicinity conversions by type are shown in Table 5 below. A summary of the projected unit costs associated with post top conversions is shown in Table 6 below. Projected vicinity conversion expenditures are summarized in Table 7 below.

Table 5
Projected Vicinity Conversions by Type

Year	Cobrahead Vicinity Conversions	Post Top Vicinity Conversions
2026	260	1,100
2027	260	1,100
2028	260	1,100

Table 6
Post Top Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
$906.00	$854.09	$781.42

Table 7
Projected Vicinity Conversion Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2027)	$1.342 million	1,813
Test Year (ending 4/30/2028)	$1.033 million	1,360

Q. Is unit cost analysis appropriate for comparing projected capital expenditures for vicinity conversions?

A. No. Unit cost is not an appropriate basis for evaluating streetlighting vicinity conversion expenditures due to the potential difference in cost associated with materials, construction means and methods, and the type of luminaire being converted (post top or cobrahead). Although the company estimates an amount of each luminaire type (post top and cobrahead, see Table 5) of vicinity conversion for expenditure development purposes, actual conversions of each luminaire type may vary due to existing LEDs in proximity to

the failed light being replaced. For instance, a failed HID post top light is being converted to LED technology and there are no operational HID post top lights in the vicinity. The Company will manage vicinity conversions to the proposed capital expenditures shown in Table 7, recognizing the type of conversion may vary from those shown in Table 5.

Q. What level of spending was included for rate recovery by the Commission in Case No. U-21870 for the 16-month bridge period ending April 30, 2026 and test year ending April 30, 2027?

A. The Commission approved $26.432 million for recovery in current rates for the 16-month bridge period, and $16.545 million for recovery in current rates for the test year.

During the 16-month bridge period in case U-21870 (January 1, 2025 through April 30, 2026) the Company spent $31.406 million.

Q. What cost is the Company projecting for streetlighting capital investments in this case for the 16-month bridge period ending April 30, 2027 and test year ending April 30, 2028?

A. The Company is projecting $28.144 million of streetlighting capital expenditures for the 16-month bridge period, and $21.659 million of streetlighting capital expenditures for the test year.

Q. Please summarize the customer benefits of the Company's proposed streetlighting capital expenditures.

A. The Company's primary objective regarding streetlighting is to provide reliable service at the lowest reasonable cost to customers. The Company carries out this objective through conversions of older technology upon failure, installation of energy efficient lighting in

new applications, and use of self-service technology, which reduces work processing and keeps the customer informed of streetlight outage status.

Performing cobrahead, center suspension and post top LED conversions on a reactive basis provides customers with LED lighting in a fair and timely manner, without the upfront costs.

The conversion of streetlights to LED technology delivers substantial cost savings for streetlighting customers. Based on the streetlights converted to LED technology in 2025, customers will save approximately $950,000 per year in streetlighting rates beginning in 2026, resulting in an estimated $19 million in total savings over the life of the LED streetlight assets. In 2025, an additional 2,643 HID streetlights were converted to LED technology through vicinity conversion, generating $300,000 in customer savings compared to future reactive conversion costs. To date, a total of 5,711 HID streetlights have been converted to LED technology via vicinity conversion, resulting in cumulative customer savings of $597,000 when compared to future reactive conversion costs.

The Company is realizing the benefits of LED conversions through reduction of failed streetlight orders. Average streetlight outage duration was 11.50 days in 2025, a 21.5% reduction from 2024 levels. Median outage duration was 6 days in 2025, a 14% reduction from 2024 levels. The tacticslaid out in the revised Reliability Roadmap will only accelerate this reliability benefit. The Company's internal prioritization standards for restoration of outages greater than 60 days ensure all lighting outages are a priority and are restored in a timely fashion.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Sara E. Stewart and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

QUALIFICATIONS

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Forestry Operations.

Q. Please describe your educational background and work experience.

A. I have 12 years of utility experience at Consumers Energy within the Forestry Department with extensive experience in the development and execution of the Line Clearing Program. Over these years, I have held roles and performed the duties of all field and leadership positions within the Forestry team overseeing strategy and operations, as well as driven continuous improvement and technology enhancements including the development of the forestry model and workplan selection tool. I am skilled in distribution, service restoration, contract management, as well as financial management. I hold a Bachelor of Science degree in Natural Resources and Environment from the University of Michigan with a concentration on Resource Ecology and Management. I am an International Society of Arboriculture Certified Arborist and Certified Utility Specialist. I also hold a Michigan Department of Agriculture and Rural Development Pesticide Applicator Certification.

Q. What are your responsibilities as Director of Forestry Operations?

A. I have responsibilities for all forestry functions including line clearing, budgeting, planning, and operations for the Company's distribution system.

Q. Have you testified in previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have filed testimony about the Company's Line Clearing Program in MPSC Case No. U-21870 (General Electric Rate Case).

Q. What experience do you have related to other previous cases?

A. I supported Pamela L. Bolden and Chris A. Shellberg as they prepared testimony and exhibits in several rate cases: Case Nos. U-21585, U-21389, U-21224, U-20963, and U-20697. I also participated in the distribution audit in Case No. U-21305 by preparing responses to the Liberty Consulting Group's ("Liberty") written audit requests and being interviewed and have had oversight of the Company's Line Clearing Program Annual Report and Line Clearing Program Formal Optimization Analysis of Line Clearing Cycles in Case No. U-20697.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to describe the Company's Line Clearing Program, explain how its increasingly aggressive line clearing cycle and practices will reduce outages and improve service for electric customers, and support the Company's request in this case for funding to support these efforts. My direct testimony is presented in six sections: 1) Description of the Line Clearing Program; 2) Recent Progress of the Line Clearing Program; 3) Strategy for the Line Clearing Program; 4) Reliability Benefits of the Line Clearing Program; 5) Expense Requirements for the Line Clearing Program; and 6) Resourcing Plan for the Line Clearing Program.

EXHIBITS

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-186 (SES-1)	Line Clearing O&M Expense;
Exhibit A-187 (SES-2)	Projected LVD Tree-Caused Reliability of the Line Clearing Ramp-Up Plan;
Exhibit A-188 (SES-3)	2026 HVD Line Clearing Work Plan;
Exhibit A-189 (SES-4)	2026 LVD Line Clearing Work Plan;
Confidential Exhibit A-190 (SES-5)	Post-Work Review Supporting Documentation Examples;
Exhibit A-191 (SES-6)	Summary of O&M Expenses Projected Using Inflation;
Exhibit A-192 (SES-7)	Analysis of Projected Costs, Cost Savings, and Reliability Improvements of Implementing a Four-Year Cycle for LVD Circuits; and
Exhibit A-237 (SES-8)	Analysis of Costs, Benefits, and Reliability Improvements of Removing 100% of Tree Canopy in First Zones.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

DESCRIPTION OF THE LINE CLEARING PROGRAM

Q. Please explain the Company's Line Clearing Program.

A. The Company's Line Clearing Program is responsible for maintaining clearance between vegetation and energized equipment and to eliminate vegetation hindering accessibility to the Company's electric lines. The Company uses Integrated Vegetation Management ("IVM") along the Company's electric line rights-of-way to accomplish these objectives. IVM is the practice of promoting compatible plant communities along rights-of-way using

a combination of cost-effective methods, including chemical, cultural, mechanical, or manual treatments. This work is performed by contractors with qualified line clearance tree trimmer employees, in accordance with Michigan Occupational Safety and Health Administration (MIOSHA) requirements, on production-oriented contracts with the Company. The Line Clearing Program is divided into two parts: (i) High Voltage Distribution ("HVD") Line Clearing; and (ii) Low Voltage Distribution ("LVD") Line Clearing.

Q. Please describe HVD Line Clearing.

A. HVD Line Clearing manages vegetation along the Company's high voltage systems. There are two major voltages on the Company's HVD system: 46 kilovolts ("kV") and 138 kV. The Company clears vegetation within an 80- to 120-foot-wide right-of-way for these voltages to attain a minimum of 15 feet of separation for 46 kV lines and 20 feet of separation for 138 kV lines between conductors and vegetation at the time of clearing. The Company also manages vegetation within the right-of-way to maintain accessibility along the right-of-way for maintenance and repair of the line. During scheduled maintenance line clearing, the Company identifies and removes hazard trees up to 40 feet from the edge of the right-of-way. HVD Line Clearing is divided into multiple subprograms.

Q. Please explain what projects, activities, and other types of work will be funded by spending in HVD Line Clearing.

A. HVD Line Clearing consists of an IVM program that promotes reliability by reducing tree-caused outages and decreasing the impact of storms. HVD Line Clearing consists of three subprograms: (i) maintenance clearing; (ii) brushing and herbicide treatment; and

(iii) demand clearing. HVD Line Clearing also includes Forestry Operations Administration expenditures.

The IVM program provides reliability benefits to customers while maintaining and promoting a healthy ecosystem along the Company's HVD rights-of-way. The Company's HVD and LVD rights-of-way are enrolled in the U.S. Fish and Wildlife Service's Conservation and Consent Agreement with Assurances ("CCAA") for the monarch butterfly. The CCAA also requires protection for other pollinator species as well as threatened and endangered species that are found in these areas.

Q. What is HVD maintenance clearing?

A. The Company's HVD maintenance clearing work consists of scheduled cycle maintenance activity for trimming and removing trees within the right-of-way corridor and includes hazard tree removal outside of the right-of-way. HVD rights-of-way are typically cleared 40 feet on either side of the centerline to remove all tree species and shrubs that inhibit right-of-way access. Specimen trees growing along city streets or landscaped residential properties may be trimmed to attain a minimum of 15 to 20 feet of clearance instead of removal. A tree outside of the right-of-way is considered a hazard tree if it is tall enough to strike the HVD line if it fell and if it is dead, diseased, infected with destructive insects, or structurally weakened.

Q. What is HVD brushing and herbicide treatment?

A. The Company conducts brush cutting and herbicide treatment in HVD rights-of-way to reduce the volume of small trees growing within the right-of-way before they grow to a height that may interfere with the line. This work also allows line worker crews to access equipment for repair or replacement. Brush control work: (i) is completed on a four-year

cycle schedule; (ii) reduces future stem volume; (iii) promotes the growth of compatible species within the right-of-way; and (iv) supports or maintains habitat needed for several endangered, threatened, or rare species of plants and animals.

Q. What is HVD demand clearing?

A. HVD demand clearing work addresses emergent vegetation threats to the Company's HVD system. These threats are identified by HVD vegetation inspections and by helicopter patrols of the HVD system. Demand clearing work most often involves partially uprooted trees that are leaning towards the line that may fall onto the line. These situations require immediate remediation to prevent an outage.

Q. Does HVD Line Clearing still include HVD noxious weed control?

A. No, it does not. The Company's noxious weed control work maintains compliance with local ordinances for maintaining vegetation on fee-owned HVD rights-of-way in predominantly urban areas. These ordinances do not permit vegetation growth above a specified height, requiring three to six mowing cycles of affected rights-of-way each year, with variation due to rainfall and temperature. This work is being transferred to the Company's Land Management department and is reflected in Company witness Quentin A. Guinn's Exhibit A-134 (QAG-2), line 2. Previous expenditures for this work are reflected in Exhibit A-186 (SES-1), line 7, columns (d) through (i).

Q. Please describe LVD Line Clearing.

A. LVD Line Clearing manages vegetation along LVD primary voltage systems and secondary voltage systems, including service conductors. The Company clears vegetation within a 30-foot-wide right-of-way for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing and to maintain

accessibility along the right-of-way for maintenance and repair of the line. As a part of LVD Line Clearing, hazard trees, such as dead or dying trees that are within 20 feet of the edge of the right-of-way that are accessible to aerial lift trucks, are removed when not objected to by the property owner. LVD Line Clearing is divided into multiple subprograms.

Q. Please explain what projects, activities, and other types of work will be funded by spending in LVD Line Clearing.

A. LVD Line Clearing consists of seven subprograms: (i) program maintenance (full circuit clearing); (ii) repetitive outage zonal clearing; (iii) Customers Experiencing Multiple Interruptions ("CEMI") clearing; (iv) first zone clearing; (v) Load Concentration Point ("LCP") zonal clearing; (vi) demand clearing (customer requested work); and (vii) brushing-spray. LVD Line Clearing also includes Forestry Operations Administration expenditures.

Q. What is LVD program maintenance (full circuit clearing)?

A. LVD program maintenance clearing is the predominant, scheduled maintenance clearing work for the LVD system. Trees are cleared to attain at least 10 feet of clearance to LVD primary conductors. Secondary voltage conductors and services are cleared of any tree limbs displacing or rubbing on these conductors. Brush (sapling trees and woody shrub species) is cut within the 30-foot right-of-way. Hazard trees (dead, dying, or mechanically stressed trees) within 20 feet of the edge of the right-of-way are removed when not objected to by the property owner.

Q. What is LVD repetitive outage zonal clearing?

A. LVD repetitive outage zonal clearing targets specific sections of circuits that are experiencing high levels of tree-caused outages. Monthly, the Company reviews sections of circuits for multiple tree-related, non-Major Event Day ("MED") outages within the previous 12 months. Identified sections are scheduled for clearing based on system reliability impacts and resource limitations. These sections are cleared to the same specifications as program maintenance work.

Q. What is LVD CEMI clearing?

A. LVD CEMI clearing is designed to target customers experiencing high numbers of outages during the current calendar year and reduce the likelihood that these customers will experience similar outages going forward. CEMI clearing differs from repetitive outage clearing as CEMI is focused on the cumulative effect of all upstream LCPs from the customer's location, whereas repetitive outage is focused on the number of outage incidents in a particular LCP. For CEMI, no particular LCP may be experiencing outage rates at the repetitive outage level, but the cumulative effect of multiple upstream devices, each with just a few outages, results in the customer having many outages. CEMI clearing targets selected areas upstream of the customer location to reduce future tree-caused outages. CEMI areas may be cleared to the same specifications as program maintenance or select individual trees may be targeted for clearing depending on the vegetation conditions of the CEMI-identified section and the length of the section to be cleared.

Q. What is LVD first zone clearing?

A. LVD first zone clearing targets the section of a circuit from the substation outward to logical LCPs. Typically, these are three phase structures (poles with X, Y, and Z phasing)

and any unfused laterals extending from this first zone. Although these zones may have lower outage frequency than other areas, outages that do occur impact a higher number of customers. This work reduces the likelihood of full circuit lockouts due to trees and provides reliability benefits for all customers connected to the circuit. Each fall when work plans are developed for the upcoming year, first zones are selected for this subprogram based on their previous 12-month tree-related outage history. Clearing of first zones is targeted in first and second quarters of the workplan year to maximize the reliability benefits to all customers of the circuit. First zones are currently cleared to the same specifications as program maintenance with the exception that, starting in 2026, the highest customer density first zones (circuits that serve 350 customers or more, as described later in my testimony) will have canopy removed over their three phase lines during scheduled O&M line clearing.

Q. What is LVD LCP zonal clearing?

A. To comply with the Settlement Agreement for MPSC Case No. U-21224, the Company incorporated LVD LCP zonal clearing as a new subprogram starting in 2024 that targets the worst performing zones across the LVD system. In the 2025 calendar year, the Company cleared 85 miles under the LCP zonal clearing subprogram. These sections are cleared to the same specifications as program maintenance work. This subprogram differs from the repetitive outage subprogram in that LCP zonal clearing work is evaluated and added to the annual work plan at the beginning of the calendar year, whereas repetitive outage work is evaluated monthly.

Q. What is LVD demand clearing?

A. LVD demand clearing addresses emergent vegetation threats to the LVD system. Emergent vegetation threats are identified predominantly by customers calling in personal observations around their homes, from forestry operations personnel, and from other electric operations employees performing duties in the field. The Company's forestry operations personnel review these requests in person, or through phone conversations, with the reporting party to validate the emergent nature and the likelihood of an outage. Work that can wait until maintenance clearing will be performed is delayed, but validated threats to the system are prioritized and addressed based on potential system reliability impacts and resource limitations.

Q. What is LVD brushing - spray?

A. LVD brushing - spray uses herbicide applications to treat brush within the LVD right-of-way two to three years following full circuit clearing, particularly on rural and suburban circuits with higher brush densities in the right-of-way. This work reduces future stem volume, promotes the growth of compatible species within the right-of-way, and helps maintain accessibility for line maintenance or repair. Brush growing in or near wetlands or open water bodies is manually or mechanically cut instead of being treated with herbicides.

Q. What standards apply for trimming trees along service lines?

A. Customer service lines are cleared of trees or parts of trees that are displacing or rubbing on these conductors. Service line clearing is identified and occurs during program maintenance (full circuit clearing) and other scheduled Operating and Maintenance ("O&M") subprograms. The Company also addresses tree issues along service lines

outside of scheduled O&M subprogram clearing on an emergent basis through its demand subprogram by removing trees or parts of trees that have fallen on service lines and trimming limbs that are causing damage to conductors.

Q. Does the Company perform quality assurance of line clearing work done in the field by contractors?

A. Yes. In accordance with Rule 505 of the Commission's Technical Standards for Electric Service, Mich Admin Code, R 460.3505, as amended through MPSC Case No. U-20630, the Company performs quality assurance of line clearing work through its standard post-work review process for scheduled O&M projects. After planned line clearing work is completed, the contractor submits a Circuit Closing Form for each section of circuit. A statistically relevant representative inspection is then completed where the Company reviews the work in the field to ensure clearance is obtained and hazard trees are removed as planned. If trees, brush, or vines were missed by the line clearing contractor, tree crews are sent back to complete the work on non-billable time. Upon completion of this re-work, the contractor submits a Weekly Summary Crew Report identifying when, by whom, and with what equipment the non-billable work was completed. Confidential Exhibit A-190 (SES-5) contains documentation supporting this process. As an example, for scheduled O&M work, the Company required 301 hours of non-billable labor in 2025 identified through its post-work review process. It is important to note that the Company has internal forestry operations personnel presence in the field as work is being completed by line clearing contractors, which results in quality assurance checks and corrections throughout work completion. It is in the best interest of the Company, its electric customers, and its line clearing contractors to prevent defects and increase first-time quality of work, thus

driving down the number of defects discovered in post-work review and resulting non-billable labor hours.

Q. Does the Company's Line Clearing Program include clearing required for service restoration?

A. Forestry is a key piece of the Company's service restoration efforts. Forestry manages the tree crews during restoration events, working together with many other areas of the Company to restore service or address emergent threats to the system. The costs for this work are captured in service restoration expenses. Service restoration expenses are addressed by Company witness Jeffrey P. Dickey and are not a part of the line clearing funding discussed in my direct testimony. However, the funding requested for line clearing establishes a base of tree crews working on the system that are utilized for service restoration work when needed.

RECENT PROGRESS OF THE LINE CLEARING PROGRAM

Q. Please describe the Company's recent progress in HVD Line Clearing.

A. The Company has continued to maintain a four-year clearing cycle for its HVD system. Figure 1 below shows actual clearing and expenditure data for the previous five years and a summarization of the most recent four years of clearing towards the cycle.

FIGURE 1
HVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	4-Year Cycle 2022-2025
Cleared Miles	1,178	1,106	1,153	1,203	1,059	4,521
Planned Miles	1,129	1,161	1,164	1,166	1,104	4,595
O&M Expense ($M)	$10.74	$10.99	$11.30	$10.73	$9.67	$42.69
Planned O&M Expense ($M)	$12.60	$11.71	$12.06	$12.28	$12.20	$48.25
$/line mile	$9,117	$9,932	$9,801	$8,919	$9,133	$9,443
Clearing Cycle (years)	4.2	4.2	4.2	4.0	4.3	4.1

Q. Please list any prioritized projects for maintenance clearing work in HVD Line Clearing for 2026.

A. In 2026, the Company is planning HVD line clearing on the lines listed in Exhibit A-188 (SES-3).

Q. Please describe the Company's recent progress for LVD Line Clearing.

A. The Company had been working towards attaining a seven-year effective clearing cycle for its LVD system in recent years. In Case No. U-21870, the Company first introduced its vision to ramp-up to a five-year clearing cycle and perform more aggressive line clearing on targeted three phase primary lines. Figure 2 below shows the most recent five-year actual clearing miles, expenditure data, workplan backlog and cycle percentages, and a summarization of the most recent five years of clearing compared to a five-year cycle target.

FIGURE 2
LVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	5-Year Actual 2021-2025
O&M Cleared Miles	5,279	6,388	6,365	6,030	6,790	30,852
O&M Planned Miles	5,223	5,636	5,875	6,760	6,765	30,259
O&M Expense ($M)	$75.83	$91.02	$97.79	$99.49	$125.50[1]	$489.63
Planned O&M Expense ($M)	$71.43	$81.49	$87.97	$105.37	$113.20[1]	$459.46
$/line mile	$14,364	$14,248	$15,364	$16,500	$18,485	$15,870
Effective Clearing Cycle[2] (years)	10.6	9.1	9.3	9.7	8.3	9.3
Workplan Backlog[3] Miles Percentage	87%	67%	82%	80%	89%	81%
Workplan Cycle[3] Miles Percentage	13%	33%	18%	20%	11%	19%

[1] Includes wildfire mitigation expenditures.
[2] Effective clearing cycle is calculated by total system miles divided by the cleared miles.
[3] Years 2021-2025 are calculated using the previous seven-year effective cycle strategy.

Q. Please explain the workplan backlog and cycle miles percentages shown in Figure 2.

A. The workplan backlog and cycle miles percentages shown in Figure 2 reflect the cycle strategy for the column year. For example, the Company was executing on a seven-year effective cycle strategy in years 2021 through 2025, and the backlog miles percentage reflects the percentage of circuit miles last cleared outside of the previously intended clearing cycle for the three main voltage classes. The mileage and expense utilized in Figure 2 encompasses LVD full circuit clearing, LVD subprogram clearing, and LVD subprogram brushing - spray miles.

Q. How will workplan backlog and cycle miles percentages be calculated under the five-year cycle strategy?

A. Starting in 2026, backlog and cycle miles percentages will be calculated utilizing full circuit clearing miles only. Cycle miles will encompass circuits last fully cleared 5 years prior to the clearing year, and backlog miles will encompass circuits last fully cleared greater than 5 years prior to the clearing year.

Q. Please list any prioritized projects for full circuit clearing work in LVD Line Clearing for 2026.

A. Exhibit A-189 (SES-4) shows the 2026 LVD work plan which includes cycle circuits (i.e., a circuit that has reached five years since it was last fully cleared), backlog circuits informed by the forestry model, and carryover circuits (i.e., circuits begun in 2025 with completion carrying over to 2026).

Q. Please describe the seven-year effective cycle and how it works.

A. The seven-year effective cycle describes the retired strategy of clearing one-seventh of LVD system miles per year with different targeted cycle lengths of clearing for the three

major primary voltages on the LVD system. If the seven-year effective cycle were achieved, 14.4/24.9 kV circuits would be cleared on average between four to six years, 7.2/12.47 kV circuits would be cleared on average between six to eight years, and 4.8/8.32 kV circuits would be cleared on average between eight to ten years depending on the circuits' historical performance, reliability predictions from the forestry model, and safety considerations. The Company first used historical actual data in MPSC Case No. U-20697 to justify that the seven-year effective cycle was the most cost-beneficial approach to reducing tree-related outages on the LVD system at current system conditions. Figure 3 shows the annual clearing miles schedule required to maintain the seven-year effective cycle for the LVD system once achieved.

FIGURE 3
LVD CLEARING SCHEDULE FOR 7-YEAR EFFECTIVE CYCLE

Substation Voltage Class	Approximate System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Class
14.4 kV	18,000	3,600	5 years
7.2 kV	10,700	1,529	7 years
4.8 kV	32,300	3,589	9 years

Q. Has the Company made LVD line clearing specification changes in recent years?

A. Yes, the Company has made changes to its line clearing specification in recent years. In 2009, it added enhanced overhang clearance requirements for weak-wooded species overhanging primary wires from 15 feet to 20 feet. In 2016, the Company incorporated hazard tree removal as part of its base LVD primary line clearing specifications. In 2026, the Company incorporated more aggressive line clearing along targeted LVD three phase primary lines during scheduled O&M line clearing work. More aggressive line clearing is

defined as the practice of canopy removal, which is the removal of all branches above primary wires.

Q. What technology enhancements has the Company utilized in its Line Clearing Program?

A. The Company modernized its forestry model by harnessing more sophisticated predictive and prescriptive analytics in Machine Learning and satellite imagery analysis to influence and guide its LVD full circuit clearing subprogram. The forestry model was built into a web-based tool, called the forestry workplan selection tool, to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing work plan to capture the most reliability and safety benefits for annual spend. The output of the forestry model is an input into the forestry workplan selection tool. This technology was first utilized to generate the 2023 LVD full circuit clearing work plan and has continued to be used annually. The underlying forestry model that is built into the forestry workplan selection tool is retrained on the most up-to-date data sources annually for an updated risk assessment.

Q. Please explain how the forestry workplan selection tool works and how it functions to reduce tree-caused outages.

A. The forestry workplan selection tool uses the output of the forestry model, which is a Machine Learning model that uses hundreds of data inputs to predict tree-related reliability impacts across the LVD system for the following year. Because an understanding of individual circuit return on investment is necessary to capture the highest reliability benefits for the spend, this selection tool includes the use of satellite imagery analysis to more accurately project costs to clear each circuit. Reliability predictions coupled with

historical safety performance (e.g., hazard events including trees on line, wires down, etc.) and cost projections are then fed into an optimization engine with parameters identified (e.g., budget) to automatically generate a targeted LVD full circuit clearing workplan that captures the highest amount of reliability and safety risk.

STRATEGY FOR THE LINE CLEARING PROGRAM

Q. What is the Company's strategy for its Line Clearing Program?

A. The Company's strategy for its Line Clearing Program is simple: fewer tree-caused outages on its system that will improve electric reliability for its customers in all conditions. To achieve this, the Company is maintaining a four-year clearing cycle for its HVD system and, for its LVD system, executing on a ramp-up strategy to a five-year clearing cycle and performing more aggressive line clearing on targeted three phase primary lines. The projected timeline to achieve the shortened line clearing cycle and scope of more aggressive line clearing is by the end of the 2030-2031 test period. Additionally, the Company implemented an LVD tree-caused outage review program to perform deeper causal analysis of tree-caused outages to provide valuable insights and inform future line clearing strategy decisions.

Q. Please describe the five-year cycle strategy and how it works.

A. The five-year cycle strategy describes clearing one-fifth of the Company's LVD line miles annually in steady-state cycle maintenance while maintaining the standard that all LVD circuits have been fully cleared within a five-year period. The Company's strategy includes a ramp-up plan to eliminate all backlog miles (circuits that have not been fully cleared within five years) by the end of the 2030-2031 test period. During this ramp-up period, the Company will utilize its forestry workplan selection tool to inform the

sequencing of backlog reduction based on its optimization outputs for reliability and safety risk. After the ramp-up period, steady-state cycle maintenance begins. At that time, the Company will evaluate other tactics for continuous improvement in risk management, including cycle change considerations.

Q. What miles metric is the Company tracking as progress towards the five-year LVD line clearing cycle?

A. The Company is tracking LVD full circuit clearing miles as the main metric towards attaining the line clearing cycle and is tracking other miles (LVD subprogram clearing miles, LVD subprogram spray miles, and LVD capital clearing miles) separately and not as part of the standard cycle. This metric is shown in Exhibit A-186 (SES-1), line 23. This ensures the entire LVD system is brought to a consistent state with no circuits or sections of circuits left in backlog status.

Q. If the LVD system is to be on a five-year cycle by the end of the 2030-2031 test period, what will happen to non-full circuit clearing subprograms?

A. As the LVD system grows nearer to being on a five-year cycle, the necessity of partial circuit clearing subprograms for reliability intervention (repetitive outage zonal clearing, CEMI clearing, first zone clearing, LCP zonal clearing) lessens. Continuing through the 2030-2031 test period, the Company will phase out these subprograms for backlog circuits in favor of full circuit clearing for these circuits to bring them on cycle. After the 2030-2031 test period when the LVD system is projected to be fully on-cycle, the Company will only perform these activities on mid-cycle circuits if the need arises. The Company finds

that mid-cycle clearing is a common practice among utilities it conducts benchmarking with.[4]

Q. How will the Company address the backlog of circuits not cleared in many years?

A. The Company's strategy to attain a five-year line clearing cycle by the end of the 2030-2031 test period is made possible by preventing any on-cycle circuit from exceeding its cycle and becoming a backlog circuit starting with the test period of Case No. U-21870. In practice, this means any LVD circuit that reaches five years since it was last fully cleared, therefore reaching its cycle length, is automatically included in the annual work plan for the year to be kept on cycle. As projected in Figure 4, any remaining miles for the work plan will be backlog miles, addressed throughout the ramp-up strategy timeframe of Case No. U-21870 test period (Year 1) through the 2030-2031 test period (Year 5) and informed by the forestry model that is built into the forestry workplan selection tool.

FIGURE 4
PROJECTIONS FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Ramp-Up Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	8,890	4,099	4,791	26,275
Year 2	11,535	6,347	5,188	21,087
Year 3	13,077	6,257	6,819	14,267
Year 4	13,993	6,259	7,734	6,533
Year 5	14,002	7,469	6,533	0

Q. Why did the Company deviate from its previous seven-year effective cycle strategy?

A. In its final report, Liberty recommended the Company achieve a four-or-five-year line clearing cycle for LVD circuits by year-end 2028. While the Company has always

[4] Specifically, Alliant Energy, Ameren Missouri, American Electric Power perform mid-cycle clearing.

acknowledged the reliability benefits of shorter cycles (i.e., a reduced cycle results in lower tree-caused outage rates on the LVD system), it sought to balance reliability benefits with costs to implement and maintain the cycle. In previous rate case analyses – rate cases that preceded Case No. U-21870 – a seven-year effective cycle was outlined as the most cost-beneficial approach for customers. Since then, additional data analysis and information, including Liberty's recommendation and report, had become available for consideration. The Company carefully evaluated projected costs and benefits of a shorter line clearing cycle for its LVD circuits and determined that a five-year line clearing cycle is the right approach to significantly improve electric reliability while responsibly managing customer bill impacts. The Company first presented this strategy in Case No. U-21870.

Q. Has the Company studied the costs and benefits of moving its LVD system to a four-year cycle?

A. Yes. To comply with the Order for Case No. U-21870, the Company studied the costs and benefits of moving its LVD system to a four-year cycle using the same methods as it did to project the costs and benefits of moving the LVD system to a five-year cycle. This study is displayed in O&M Exhibit A-192 (SES-7), detailing the projected costs and benefits of implementing a four-year cycle and satisfying the Commission's directive that the Company provide "an O&M exhibit detailing the costs of implementing a four-year cycle."

Q. What is the Company's assessment of contractor costs associated with transitioning towards a four-year cycle?

A. The Company's assessment of contractor costs associated with transitioning towards a four-year cycle is displayed in Exhibit A-192 (SES-7), line 19, columns (c) through (g), which assumes a 0% change in costs in the 2027 calendar year. The Company estimates

an O&M contractor expense of $1.277 billion to implement a four-year cycle in a similar timeframe as the Company plans to implement its five-year cycle, which is $216.428 million above the Company's projected expense to implement the five-year cycle.

Q. Has the Company considered the availability of securing line clearing contractor contracts under a four-year cycle? If yes, what concerns exist?

A. Yes, as directed by the Commission, the Company has considered the availability and cost of securing line clearing contractor contracts under a four-year cycle; the Company currently has 10 line clearing contractor contracts, is in the process of adding two more, and believes additional contracts could be secured. The Company's concern is not with securing line clearing contractor contracts, but with attracting and retaining even more out-of-state line clearing crews within an industry that has high demand and limited resources throughout the country. Estimated line clearing crew resourcing levels to transition towards a four-year cycle are displayed in Exhibit A-192 (SES-7), line 20, columns (c) through (g). To attract and retain additional out-of-state line clearing crews above the Company's five-year line clearing cycle ramp-up plan, displayed in Exhibit A-192 (SES-7), line 36, columns (c) through (g), it must offer even higher nationally competitive wages and per diems, in direct competition with other utilities that are also aggressively expanding their line clearing programs. This would drive up the expense of attaining an even shorter cycle. Once the Company is on its five-year cycle, it projects the need for out-of-state tree crewing is eliminated due to the efficiencies a shorter cycle brings. The incremental cost of moving from a five-year cycle to a four-year cycle may be prudent in the future.

Q. Did the Company perform an analysis of any cost savings associated with and reliability improvements gained by moving to a four-year line clearing cycle?

A. Yes, as directed by the Commission, the Company performed an analysis of the cost savings associated with and reliability improvements gained by moving to a four-year line clearing cycle. Cost savings include the estimated Service Restoration cost avoidance due to prevented tree-caused outage events and the estimated customer cost avoidance due to prevented interruptions, informed by the Interruption Cost Estimate ("ICE") Calculator 2.0[5], displayed in Exhibit A-192 (SES-7) on lines 33 and 34, columns (c) through (g). The Company estimates that moving to a four-year line clearing cycle compared to moving to the five-year line clearing cycle could result in approximately 2.5-2.9% reliability improvement in all weather conditions from 2027 through 2031 for each metric of: primary and circuit tree-caused incidents, primary and circuit tree-caused System Average Interruption Frequency Duration ("SAIFI"), and primary and circuit tree-caused System Average Interruption Duration Index ("SAIDI"). The reliability projections of moving to a four-year line clearing cycle are displayed in Exhibit A-192 (SES-7) on lines 23 through 25, columns (c) through (g).

Q. What is the conclusion of the study of the costs and benefits of moving the LVD system to a four-year cycle?

A. The conclusion of this study demonstrates that the Company's strategy of moving its LVD system to a five-year cycle provides more net benefit than moving its LVD system to a four-year cycle in a similar timeframe. Over the five-year period, implementation of the five-year cycle results in an estimated net benefit of $298.643 million while

[5] https://icecalculator.com/

implementation of the four-year cycle results in an estimated net benefit of $273.499 million, a difference of $25.144 million in favor of the five-year cycle strategy.

Once the five-year cycle is attained, the Company will reevaluate other tactics for continuous improvement in risk management, including cycle change considerations.

Q. For the Company's strategy, what does more aggressive line clearing entail?

A. More aggressive line clearing describes the practice of canopy removal, which is the removal of all branches above primary wires, along targeted LVD three phase primary lines during scheduled O&M line clearing work. In comparison, the Company's general line clearing specification for LVD primary lines allows some canopy to remain: healthy, non-weak-wooded tree species canopy is cleared to 10-15 feet from the conductors, and certain weak-wooded tree species canopy clearance is increased to 20 feet from the conductors. The practice of canopy removal targets removal of all branches above primary wires, regardless of clearance distance, tree species, or health of limb.

Q. Has the Company previously performed canopy removal on its LVD system?

A. Yes. In 2022, the Company performed a canopy removal pilot on approximately 42 miles of three phase primary which resulted in an observed average contractor cost increase of 35% per LVD mile cleared compared to neighboring circuits. In 2025, the Company performed another canopy removal pilot on approximately 30 miles of three phase primary, which resulted in an observed average contractor cost increase of 151% per LVD mile cleared. The difference between these pilots is that the 2022 canopy removal sections selected were more characteristic of the LVD system as a whole, whereas the 2025 canopy removal sections selected reflected much more significant existing canopy and extensive work to accomplish the canopy removal. While it anticipated average contractor cost

would be higher in the 2025 pilot than the 2022 pilot, the Company chose the 2025 sections intentionally to pressure test the canopy removal process and glean learnings to apply on a broader scale. Because it is believed the 2025 pilot costs were not characteristic of the LVD system as a whole, the Company did not increase its cost per mile assumptions for canopy removal in the instant case and continued to utilize the findings from the 2022 pilot. Figures 5 and 6 show examples of canopy removal on an urban and rural section of circuit respectively, pre- and post-clearing in 2025.

FIGURE 5
CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2025



FIGURE 6
CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2025



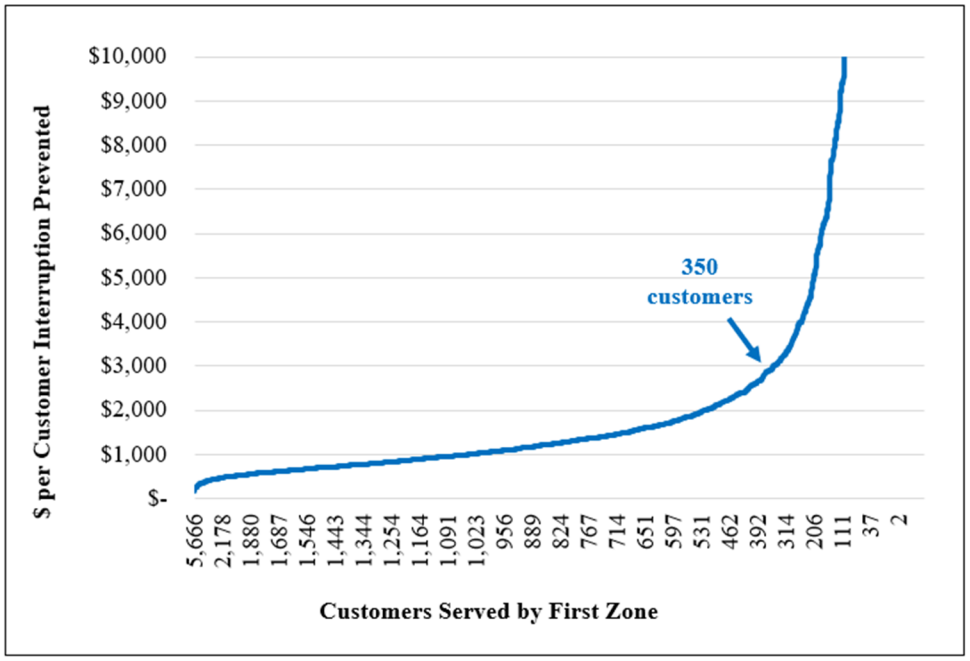
Q. Where is the Company removing canopy on its LVD system?

A. The Company's strategy includes canopy removal on roughly 5,500 miles of primary lines, targeting some three phase portions of circuits during scheduled O&M line clearing work, over the five-year ramp-up timeframe.

Q. What three phase portions of circuits are targeted for canopy removal?

A. The Company's canopy removal strategy contains two main elements: (i) within first zones, the Company uses a more aggressive threshold by targeting the three phase portions that feed 350 customers or more; and (ii) outside of first zones, the Company targets the three phase portions that feed 500 customers or more. To determine the elements of this strategy, the Company first evaluated the relationship between the incremental expense of canopy removal and the estimated customer interruptions prevented by canopy removal. Graphical representation of this data is shown below in Figure 7.

FIGURE 7
COST PER CUSTOMER INTERRUPTION PREVENTED
BY CANOPY REMOVAL IN FIRST ZONES OF LVD CIRCUITS



The knee of the curve, where costs begin to rapidly increase per customer interruption prevented, determined the first element of the Company's canopy removal strategy. The second element of the Company's canopy removal strategy aligns with the remaining canopy removal mileage it projects it can attain during the ramp-up period, scoped to the highest downstream customer density three phase outside of first zones, to maximize reliability benefits for the expense.

Q. Does the Company's canopy removal scope include 100% of first zones?

A. No, it does not. The Company's canopy removal strategy contains approximately 80% of first zone total primary miles and 85% of first zone three phase primary miles, targeting the miles that serve the most downstream customers (i.e., approximately 97% of total electric customers). The Company's strategy does not include 100% of first zone miles due to the diminishing returns in the remaining 15-20% of primary miles. The Company

evaluated adding remaining first zone miles to its canopy removal strategy, which is discussed later in my testimony, with analysis displayed in Exhibit A-237 (SES-8), and supporting data in Workpaper 1 (WP-SES-1).

Q. How will the Company measure the reliability benefits of the targeted canopy removal?

A. To measure the reliability benefits of the targeted canopy removal, the Company plans to compare the reliability improvement of circuits or zones that were cleared and had canopy removal (i.e., "treatment population") to the reliability improvement of circuits or zones that were cleared and did not have canopy removal (i.e., "control population"). This comparison is intended to isolate and measure the impact of the treatment (i.e., canopy removal) effect on reliability. The Company will include this analysis in Case No. U-20697's Line Clearing Program Annual Report, which details the progress of the line clearing program and the performance of LVD circuits post-clearing. While the Company has started executing on its canopy removal strategy, it is crucial that the dataset of the treatment population and amount of time post-treatment are of a significant size to ensure conclusions drawn from an analysis are statistically significant; therefore, measurement of the reliability benefits of the proposed targeted canopy removal will appear at the earliest in the 2027 Line Clearing Program Annual Report, filed in 2028, analyzing 2027 reliability performance. This will allow the treatment population time to begin collecting reliability data.

Q. Has the Company conducted an analysis on the costs and benefits of removing 100% of tree canopy in the first zone of LVD circuits?

A. Yes. To comply with the Order for Case No. U-21870, the Company conducted an analysis, based on available data, evaluating incremental canopy removal in addition to the strategy outlined above (i.e., adding the remaining first zone miles that are not captured in the Company's current canopy removal strategy). This analysis is displayed in Exhibit A-237 (SES-8) and supporting data is shown in Workpaper 1 (SES-1). The Company's current canopy removal strategy is named the "current strategy" in Exhibit A-237 (SES-8).

Q. What was the conclusion of the analysis?

A. The conclusion of the analysis is that it is not net beneficial to add remaining first zone primary miles to the Company's current canopy removal strategy as benefits do not overcome costs. For the analysis, costs include the incremental O&M expense of canopy removal. Cost savings include the estimated Service Restoration cost avoidance due to prevented tree-caused outage events and the estimated customer cost avoidance due to prevented interruptions, informed by the ICE Calculator 2.0. Over the five-year period of 2027-2031, adding remaining first zone primary miles to the Company's current canopy removal strategy results in a negative net benefit of $0.688 million, as shown in Figure 8.

FIGURE 8
COSTS AND BENEFITS OF ADDING REMAINING FIRST ZONE MILES TO THE CURRENT CANOPY REMOVAL STRATEGY

Description	2027	2028	2029	2030	2031	5-Year Total
Incremental LVD O&M Costs	$859,351	$970,253	$991,887	$1,035,434	$145,003	$4,001,927
Estimated Service Restoration Benefit	$6,399	$6,527	$6,658	$6,791	$0	$26,375
Estimated Customer Benefit	$601,489	$831,893	$873,435	$914,049	$66,321	$3,287,187
Net Benefit	**-$251,462**	**-$131,833**	**-$111,794**	**-$114,593**	**-$78,682**	**-$688,366**

Q. Please describe the tree-caused outage review program and how it works.

A. The purpose of the tree-caused outage review program is to gather data on a subset of LVD tree-caused outages and determine top causal contributors, establish and monitor trends, and inform future line clearing strategy decisions. Data collection occurs by outage investigators through a combination of: (i) field visits to the site where the tree-related fault occurred; (ii) conversations with field employees that responded to the outage; and (iii) conversations with in-office resources that were involved with or have knowledge about the outage. The Company utilizes contracted resources with a background in forestry and an understanding of tree species and failure modes to perform the outage investigator function.

Q. What tree-caused outages are targeted for the outage review program?

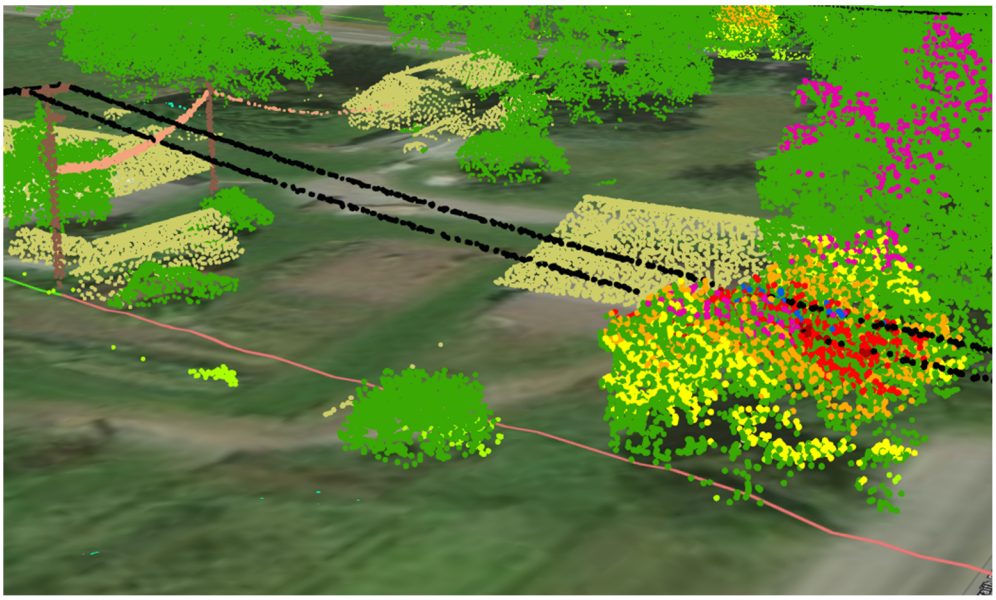
A. The Company is starting to trigger outage review when an outage meets the following criteria: (i) non-MED; (ii) circuit lockout and/or primary outage; (iii) cause code of Trees or Trees - Outside ROW; and (iv) greater than or equal to 500 customers impacted. For the last five years, there have been about 250 outages on average that meet these criteria annually. At the time of this filing, the outage review program is just starting.

Q. What line clearing tactics are the Company executing for wildfire risk mitigation?

A. While the Company is projecting to achieve the reduced cycle strategy by the end of the 2030-2031 test period for all LVD circuits, the Company is prioritizing elevated wildfire risk areas through a more aggressive timeline. Leveraging available analyses, the Company plans to achieve the five-year cycle in the elevated wildfire risk areas earlier (i.e., by year-end 2028). The Company's plan to mitigate wildfire risk in its service territory is described in Company witness Emily M. Duke's Exhibit A-98 (EMD-14).

Additionally, in 2025, the Company partnered with a vendor that performed Light Detection and Ranging ("LiDAR") collection via fixed-wing aircraft during the leaf-on season. The data processing of raw LiDAR point cloud data included three-dimensional ("3D") modeling and classification of poles and wires relative to nearby vegetation. Classified points were then transformed into actionable insights, including volumetric encroachment measurements and span-level risk scores. As this is the first LiDAR data captured on the LVD system for this purpose, the Company is conducting pilot exercises to test and evaluate intervention methods utilizing this data, which may include, but not be limited to: (i) sequencing line clearing by prioritizing pockets of high span-level risk scores first when conducting full circuit clearing on workplan circuits where possible, given environmental considerations; and (ii) evaluating spans with high risk scores on circuits that are mid-cycle for mid-cycle clearing.

FIGURE 9
3D LIDAR MAP EXAMPLE



For example, Figure 9 shows a span on an LVD circuit at the end of its five-year cycle. LiDAR points are classified utilizing a color key: brown points represent a pole,

black points represent the primary conductors, red/yellow/green points represent identified vegetation grow-in present on this span by distance, pink points represent vegetation with fall-in potential, and blue points represent vegetation overhanging the conductors.

The Company is proposing to continue its LiDAR pilot in this targeted area to enable opportunities to evaluate change detection and measure the impacts of line clearing intervention in the high-risk areas on an annual basis. The LiDAR pilot creates the opportunity for the Company to utilize a new type of data in its Line Clearing Program on a small scale first while it strengthens its abilities and evaluates expansion opportunities in the future.

Q. How is the Company enhancing its technology for the Line Clearing Program?

A. The Company continues to evaluate its Line Clearing Program processes and technology enhancement opportunities. The Company's Forestry Operations Department is utilizing Microsoft Access and Excel for system-wide program workflow management, contract invoicing, and data storage. The Company is upgrading to IT-supported systems that integrate cloud technology, support updated data storage and management infrastructure, have an improved user interface, integrate with other tools/data, enable automation opportunities, provide expansion in security and control capability, and allow for near real-time data reporting/visual management capabilities.

Q. Is the Company planning on using drone technology for its Line Clearing Program?

A. Yes, the Company is exploring the use of drone technology to research opportunities in data collection and analysis through partnership with its Forestry Operations, Unmanned Aircraft Systems, and Geographic Information System departments. Drones are being used by several utilities as a means of collecting various types of high-resolution data in targeted

areas. The Company is researching multiple sensor packages (e.g., multispectral, infra-red, and LiDAR) for targeted inspections and documentation of vegetation along the electric system. These technologies have the potential to enhance current practices by identifying declining trees early, detecting the efficacy of herbicide applications, and quantifying tree biomass volume within and along electric corridors.

RELIABILITY BENEFITS OF THE LINE CLEARING PROGRAM

Q. Why is line clearing beneficial to the Company and its electric customers?

A. Trees are the greatest cause of interruptions to electric service for customers on the LVD system and a significant cause of outages or interruptions of electric service on the HVD system. Figure 10 below shows the history of tree-caused interruptions affecting customers from 2021 through 2025 including: (i) the number of outage incidents; (ii) customers interrupted; and (iii) customer minutes of outage. The Company's Line Clearing Program is designed to minimize these occurrences, improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events. The Company's five-year cycle strategy will yield significant improvement to customers' electric service.

FIGURE 10
TREE-CAUSED RELIABILITY METRICS 2021 THROUGH 2025
ALL VOLTAGES INCLUDING MEDS (Excluding ITC incidents)

Description	2021	2022	2023	2024	2025
Incidents	24,163	17,078	18,298	20,326	20,942
Customers Interrupted	1,314,220	919,156	1,037,857	1,084,052	1,117,090
Customer Minutes (M)	1011.992	444.309	899.756	548.880	805.290

The Company's Line Clearing Program also provides benefits that are not easily quantified, such as improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contact with conductors.

Enhancing the Company's Line Clearing Program will result in less aesthetic impact to customer properties (as clearing will occur more frequently, establishing expectations with property owners) and will improve public safety.

Q. What benefits will customers realize through the requested spending level in HVD Line Clearing?

A. The Company's four-year cycle for HVD Line Clearing is effectively managing the number of HVD line outage incidents from trees within the right-of-way. The HVD system is the foundation and source for the LVD system. Outages on the HVD system can have broad impacts and can affect large numbers of customers. In the years 2021 through 2025, the average customer impact of a non-MED tree outage incident on an LVD circuit was 45 customers and the average customer impact of a non-MED tree outage incident on an HVD line was 500 customers. HVD Line Clearing benefits customers by mitigating the amount of these high customer impact outages. Additionally, outages on the HVD lines system often take longer to repair and therefore have higher customer minute impacts. Maintaining a four-year HVD line clearing cycle is necessary to minimize the impact of HVD tree outages to the LVD system and customers.

Q. What benefits will customers realize through the requested spending level in LVD Line Clearing?

A. The Company's strategy outlines a more aggressive plan of increasing the number of miles cleared each year, resulting in a decrease in the number of tree-related outages to the LVD system. Exhibit A-187 (SES-2) illustrates the projected reduction in non-MED and MED tree-caused primary outage incidents, SAIFI, and SAIDI. Figures 11, 12, and 13 below show the reliability projections by metric for 2026 through 2031 for the proposed line

clearing spending levels to achieve the Company's strategy. The values at the top of each bar represent overall reliability projections including MED.

FIGURE 11
PROJECTED 2026-2031 LVD TREE-CAUSED PRIMARY OUTAGE INCIDENTS

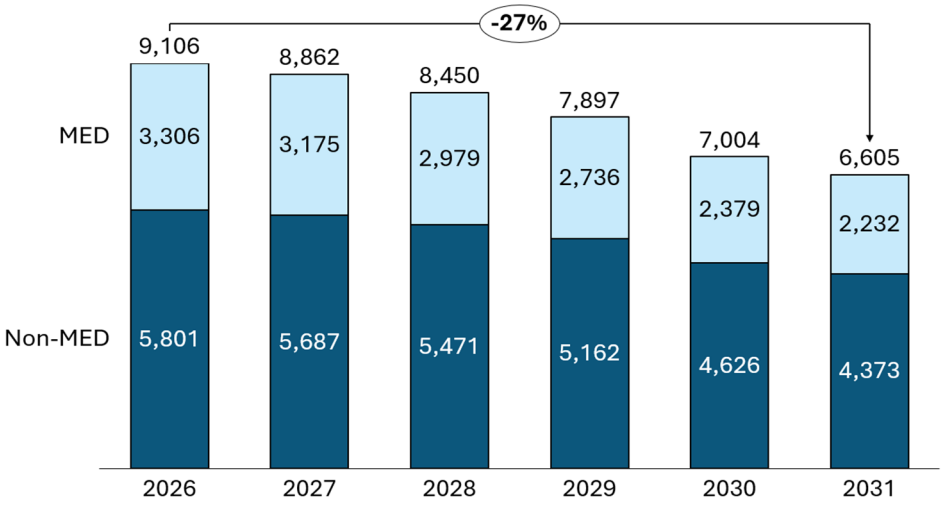


FIGURE 12
PROJECTED 2026-2031 LVD TREE-CAUSED SAIFI DUE TO PRIMARY OUTAGES

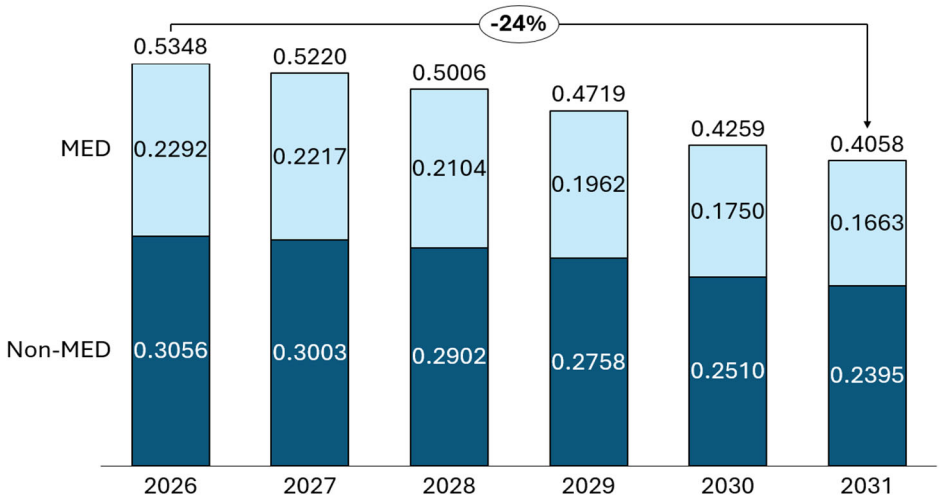
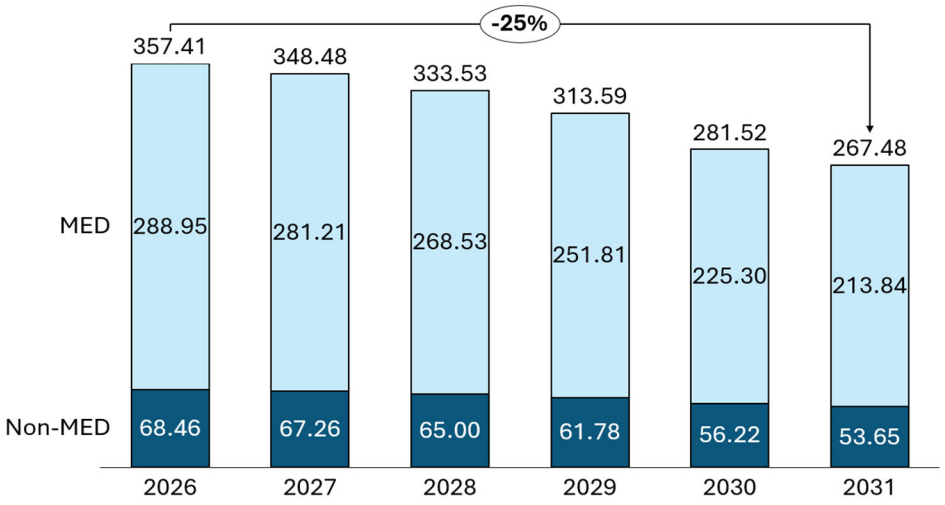


FIGURE 13
PROJECTED 2026-2031 LVD TREE-CAUSED SAIDI DUE TO PRIMARY OUTAGES



The Company's requested LVD Line Clearing spending level also supports the subprograms described earlier in my testimony that address sections of circuits from protective device to protective device, or protective device to end of circuit, that are experiencing multiple tree-related outage incidents.

Q. What is the source of these reliability projections?

A. The reliability projections in Exhibit A-187 (SES-2) are from the Company's reliability model as described in Company witness Duke's testimony, page 23, lines 1 through 10. The reliability projections in Exhibit A-187 (SES-2) also factor in the Company's canopy removal strategy on targeted three phase lines.

Q. When will reliability benefits of the new cycle be fully realized?

A. The Company projects that reliability benefits of the new cycle will be fully realized through the second clearing cycle, or roughly by 2036. Liberty's President John Antonuk discussed this phenomenon in his presentation at the Commission's September 26, 2024,

meeting,[6] attributing more significant reliability improvement across the second cycle due to a lack of completeness of line clearing work within the first cycle. While the Company agrees that it would likely not see full reliability benefits of the new cycle until the second clearing cycle, it does not agree that this is because its line-clearing work is incomplete. Rather, the partially delayed benefit Mr. Antonuk described may be driven by the lack of "wind firmness" of the surrounding healthy trees remaining after line clearing is performed that were not targeted for removal. Wind firmness is described as the ability of trees to sway with strong winds without breaking or toppling, and to return to their normal position once a wind gust or storm passes. While the Company has found little to no formal research referencing this concept as it relates to utility line clearing specifically, as most of the research concentrates on general forest management practices, the same principle applies to trees along circuits recently cleared that had not been cleared for many years prior. When many years pass between clearing, trees have more time to grow, and line clearing will result in more significant biomass removal. Trees adapt to the patterns of physical stimulation they experience as they grow,[7] and if trees have experienced a different wind pattern due to the density of surrounding trees, now removed due to line clearing, they must adapt or risk failure. The Company will utilize its tree-caused outage review program to gain deeper insights of outage causes to determine if this phenomenon is causing a significant impact to outages post-clearing.

[6] Commission Meeting, YOUTUBE (Sept 26, 2024) at ~50:30, https://www.youtube.com/watch?v=QWq5syDj94w ("For vegetation . . . the first cycle, when you advance, uh, when you shorten the cycle for vegetation, it's usually, the work is not as complete or as thorough as the second cycle, so you really, you really should start to see more, much more significant improvement across the second cycle. . . .")
[7] Amanda Bunce, *Wind and Trees 101: To Touch a Tree, Stormwise Forest Management*, University of Connecticut College of Agriculture, Health, and Natural Resources & School of Engineering (May 8, 2017), https://stormwise.uconn.edu/2017/05/08/wind-and-trees-101-to-touch-a-tree/

Q. What are the projected reliability benefits of canopy removal?

A. Benchmarking data[8] indicates a 6% outage reduction opportunity through canopy removal; therefore, the Company assumed a 6% improvement in tree-caused reliability along the portions of LVD primary that are targeted by its canopy removal strategy.

EXPENSE REQUIREMENTS FOR THE LINE CLEARING PROGRAM

Q. What are the projected expense requirements to maintain the HVD system on its four-year cycle?

A. The projected expense requirements to maintain the HVD system on its four-year cycle are displayed in Figure 14 below:

FIGURE 14
HVD LINE CLEARING SCHEDULE

Calendar Year	Data Type	O&M Maintenance Clearing Miles	Capital Clearing Miles	O&M Expense ($M)	Capital Contractor Costs ($M)	Local Crews
2021	Actual	1,178	89	$10.74	$1.80	42
2022	Actual	1,106	70	$10.99	$0.80	38
2023	Actual	1,153	29	$11.30	$0.53	38
2024	Actual	1,203	78	$10.73	$2.43	38
2025	Actual	1,059	93	$9.67	$1.42	38
2026	Projected	1,183	145	$12.04	$2.98	38
2027	Projected	1,162	143	$11.45	$2.99	38
2028	Projected	1,146	144	$11.37	$3.08	38
2029	Projected	1,070	144	$10.36	$3.13	38
2030	Projected	1,195	144	$11.73	$3.20	38
2031	Projected	1,164	144	$11.71	$3.26	38

[8] Hauer, R.J. and Miller, R.H. 2021. Utilities & Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities & Operations. Special Publication 21-1. College of Natural Resources. University of Wisconsin Stevens – Point. Page 27, Figure 6-4.
https://www.utilityvegetationmanagement.com/_files/ugd/a5c572_73c4c7e718b3467fb109eb7e8881a7b1.pdf
(Permission to use this study was obtained from its authors)

Q. What are the projected expense requirements for the LVD system ramp-up to achieve the Line Clearing Program strategy of a five-year clearing cycle and more aggressive line clearing on targeted three phase lines?

A. The projected expense requirements for the ramp-up to achieve the LVD Line Clearing strategy are displayed in Figure 15 below:

FIGURE 15
LVD LINE CLEARING RAMP-UP SCHEDULE

Calendar Year	Data Type	O&M Full-Circuit Clearing Miles	O&M Subprogram Clearing Miles	O&M Subprogram Spray Miles	Capital Clearing Miles	O&M Expense ($M)	Capital Contractor Costs ($M)	Local Crews	Out-of-State Crews	Total Crews
2021	Actual	4,647	238	395	252	$75.83	$6.07	299	0	299
2022	Actual	5,653	247	488	221	$91.02	$6.71	334	0	334
2023	Actual	5,758	165	443	169	$97.79	$5.59	348	0	348
2024	Actual	5,400	209	421	270	$99.49	$9.69	347	0	347
2025	Actual	6,092	252	445	521	$125.50[9]	$17.05	383	0	383
2026	Projected	7,891	199	405	767	$152.97	$25.35	420	80	500
2027	Projected	10,889	174	454	915	$201.85	$30.86	432	113	545
2028	Projected	12,829	149	501	924	$228.15	$31.78	432	155	587
2029	Projected	13,573	125	491	925	$233.15	$32.45	435	155	590
2030	Projected	14,834	125	508	926	$240.13	$33.13	435	155	590
2031	Projected	12,337	127	524	927	$191.99	$33.83	465	30	495

Q. Explain lines 33, 34, and 35 in Exhibit A-186 (SES-1).

A. Line 33 in Exhibit A-186 (SES-1) shows the projected baseline O&M expense for the 2026 calendar year through the 2031 calendar year and the test period. Line 34 in Exhibit A-186 (SES-1) shows the ramp-up funding which is the difference between the total O&M expense and the baseline O&M expense for the 2026 calendar year through the 2031 calendar year and the test period. Line 35 in Exhibit A-186 (SES-1) shows the credit to the regulatory asset for the 2026 calendar year through the 2031 calendar year and the test period.

[9] Includes wildfire risk mitigation expenditures.

Q. What baseline expense requirement is the Company projecting for calendar years 2027 and 2028, and the projected test period?

A. The Company projects a baseline expense requirement of $166.638 million, $169.971 million, and $167.749 million for calendar years 2027 and 2028, and the projected test period, respectively as shown in Exhibit A-186 (SES-1), columns (j, k, and o), line 33.

Q How was the baseline expense requirement calculated for calendar years 2027 and 2028, and the projected test period?

A. The baseline expense requirement for the 2027 calendar year was calculated using four months of the baseline expense approved in Case No. U-21870 of $164.446 million plus eight months of the same with 2% inflation applied. The baseline expense for the 2028 calendar year was calculated by applying 2% inflation to the 2027 calendar year baseline expense. The baseline expense requirement for the projected test period includes eight months ($8/12^{th}$) of the 2027 calendar year and four months ($4/12^{th}$) of the 2028 calendar year to create a 12-month period.

Q. What level of spending is the Company requesting in the instant case for calendar years 2027 and 2028, and the projected test period for its Line Clearing Program?

A. As discussed below in greater detail under each subprogram of my direct testimony, the Company is proposing to spend $213.300 million and $239.516 million for line clearing in calendar years 2027 and 2028, respectively, and $222.039 million in the projected test period, as shown in Figure 16 below and in Exhibit A-186 (SES-1). After subtracting the proposed baseline amounts for each of these periods discussed above, the Company is requesting Commission approval to defer to the "ramp-up" regulatory asset amounts up to $46.662 million, $69.545 million, and $54.289 million for calendar years 2027 and 2028,

and the projected test period, respectively. If the Company exceeds the total proposed line clearing expenses, the amount of the deferral will be capped at these requested amounts.

Additionally, while Exhibit A-186 (SES-1) presents projected baseline O&M expense and "ramp-up" funding for each calendar year through 2031 in order to achieve the 5-year cycle, the Company is only requesting approval of the amounts through calendar year 2028 within the instant case. The Company expects to refine its estimates of baseline O&M and required "ramp-up" deferral amounts for the remaining periods in the "ramp-up" cycle in a future rate case based on actual experience, progress in achieving the cycle, and updated cost projections, among other items.

FIGURE 16
LINE CLEARING EXPENSES
CALENDAR YEARS 2027 AND 2028, AND THE PROJECTED TEST PERIOD

Categories	2027 Calendar	2028 Calendar	Test Period
HVD Line Clearing	$10,350,199	$10,237,807	$10,312,735
LVD Line Clearing	$190,630,306	$216,112,498	$199,124,370
Line Clearing Admin	$12,319,672	$13,165,642	$12,601,662
Total O&M Expense	**$213,300,177**	**$239,515,947**	**$222,038,767**
Baseline O&M Expense	$166,638,479	$169,971,248	$167,749,402
Requested Ramp-Up Funding	$46,661,698	$69,544,698	$54,289,365

Q. What is the line item in Figure 16 titled Line Clearing Admin?

A. Line Clearing Admin is the internal salaries and expenses of the Company's Forestry Operations Department, which administers the contracts and oversees the performance of the Company's line clearing contractors. It also includes the contract foresters and work planners utilized through a contract with ArborMetrics Solutions LLC that plan the work and interact with customers. This amount for the 2027 calendar year is reflected in Exhibit A-186 (SES-1), column (j), lines 30, 31, and 32.

Q. What inflationary rates were used to determine the projections in Figure 16?

A. The Company's internal labor expenses for Forestry Operations shown in Figure 16 and Exhibit A-191 (SES-6) are a combination of current staffing, anticipated retirements, replacement and new hiring, merit increases, employee expenses, and contracted planning resources. Please refer to the direct testimony of Company witness Hannah L. Patton, page 14, lines 13 through 16, for details on the Company's projected merit and inflationary rates, which were utilized for Line Clearing Admin expense projections. All contractor rates are contractually limited through mid-2029 to an annual adjustment up to a maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443. Figure 17 below shows the 2025 results for Producers Price Indices WPUFD4 and WPU443 published January 30, 2026. For the February 2026 inflation adjustment, based on the 2025 data, the Company held equipment rates constant due to a negative WPU443 inflation rate.

FIGURE 17
PPI COMMODITY DATA FOR ANNUAL CONTRACTOR RATE ADJUSTMENT

PPI Commodity Data
12-Month Percent Change
Series Id: WPUFD4
Not Seasonally Adjusted
Series Title: PPI Commodity data for Final demand, not seasonally adjusted
Group: Final demand
Item: Final demand
Base Date: 200911
Years: 2020 to 2025

	Percent Change												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2020	2.0	1.1	0.3	-1.5	-1.1	-0.7	-0.3	-0.3	0.3	0.6	0.8	0.8	0.2
2021	1.6	3.0	4.1	6.5	7.0	7.6	8.0	8.7	8.8	8.9	9.9	10.0	7.0
2022	10.1	10.4	11.7	11.2	11.1	11.2	9.7	8.7	8.5	8.2	7.4	6.4	9.5
2023	5.7	4.7	2.7	2.3	1.1	0.3	1.1	1.9	1.8	1.1	0.8	1.1	2.0
2024	1.0	1.6	2.0	2.3	2.5	2.9	2.4	2.1	2.1	2.8	2.9	3.5	2.4
2025	3.8	3.4	3.2	2.4	2.7	2.4	3.2	2.7	3.0	2.8	3.0	3.0	3.0

PPI Commodity Data
12-Month Percent Change
Series Id: WPU443
Not Seasonally
Series Title: PPI Commodity data for Rental and leasing of goods (partial)-Construction, mining, and forestry
Group: Rental and leasing of goods (partial)
Item: Construction, mining, and forestry machinery and equipment rental and leasing
Base Date: 200903
Years: 2020 to 2025

	Percent Change												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2020	-1.6	-1.7	-0.1	-1.1	-1.9	-2.4	-3.8	-3.3	-4.4	-4.6	-4.3	-4.6	-2.8
2021	-4.8	-4.6	-4.0	-2.6	-2.5	-2.4	-0.4	-0.4	1.0	1.4	2.0	2.1	-1.3
2022	1.9	2.5	1.4	1.6	3.3	4.9	4.4	7.5	7.3	7.1	6.5	8.1	4.7
2023	9.8	9.2	9.2	9.3	7.7	5.8	6.3	2.2	2.5	2.7	2.5	1.2	5.6
2024	-0.1	-1.0	0.5	0.1	-0.8	0.0	-0.4	1.0	0.8	0.4	0.7	0.2	0.1
2025	0.1	0.9	-1.2	-0.7	0.2	-0.4	0.3	-0.2	-1.1	-1.4	-1.3	0.2	-0.4

Q. What is the Company's projected 2027 calendar year and test year spending level, for which it is requesting cost recovery, in HVD Line Clearing?

A. The Company is projecting HVD Line Clearing expenses of $11.454 million in the 2027 calendar year and $11.425 million in the test period, as shown in Figure 18 below and in Exhibit A-186 (SES-1).

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the 2027 calendar year and test period for each category as identified in Figure 18 below:

FIGURE 18
HVD LINE CLEARING EXPENSES
2027 CALENDAR YEAR AND TEST PERIOD

	2027 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Maintenance clearing	$4,838,099	579	$4,858,354	577
Brush control	$5,452,100	579	$5,394,381	576
Demand	$60,000	4	$60,000	4
Noxious weed control[10]	$0	n/a	n/a	n/a
Line Clearing Admin	$1,104,192	n/a	$1,112,437	n/a
Total	**$11,454,391**	**1,162**	**$11,425,172**	**1,157**

Q. What spending level for HVD Line Clearing was approved in the Company's last electric rate case order?

A. In MPSC Case No. U-21870, the Company requested a line clearing spending level of $186.684 million. I testified in that case that the HVD allocation would be $11.987 million for the 2026 calendar year and $11.546 million for the 2027 calendar year, which equated to $11.840 million in the 2026 test period (May 2026 through April 2027).

Q. Does the Company request to recover the entirety of its HVD Line Clearing O&M spending in the test period through base rates?

A. Yes, it does.

Q. What is the Company's projected 2027 calendar year and test year spending level, for which it is requesting cost recovery, in LVD Line Clearing?

A. The Company is projecting LVD Line Clearing expenses of $201.846 million in the 2027 calendar year and $210.614 million in the test period, as shown in Figure 19 below, and in Exhibit A-186 (SES-1).

[10] This work is being transferred to the Company's Land Management department and is reflected in Company witness Quentin A. Guinn's Exhibit A-134 (QAG-2), line 2.

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the 2027 calendar year and test period for each category as identified in Figure 18 below:

FIGURE 19
LVD LINE CLEARING EXPENSES
2027 CALENDAR YEAR AND TEST PERIOD

	2027 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Full Circuit Clearing	$181,625,523	10,889	$190,162,644	11,535
Repetitive Outage	$1,114,969	37	$1,076,646	35
CEMI Clearing	$600,000	18	$583,333	17
First Zone Clearing	$900,000	45	$866,667	43
LCP Zonal Clearing	$589,814	36	$559,876	34
Demand Work	$1,800,000	39	$1,708,537	37
Brush Control	$4,000,000	454	$4,166,667	470
Line Clearing Admin	$11,215,480	n/a	$11,489,225	n/a
Total	**$201,845,786**	**11,517**	**$210,613,595**	**12,171**

Q. What spending level for LVD Line Clearing was approved in the Company's recent electric rate case orders?

A. The approved spending level for LVD Line Clearing in the Company's recent electric rate case orders is outlined in Figure 20 below:

FIGURE 20
LVD LINE CLEARING AUTHORIZED SPEND

MPSC Case No.	Timeframe	LVD Authorized Spend ($M)
U-20697	January 2021 - December 2021	$71.430
U-20963	January 2022 - December 2022	$81.089
U-21224	January 2023 - December 2023	$87.966
U-21389	March 2024 - February 2025	$106.608
U-21585	March 2025 - February 2026	$113.168[11]
U-21870	March 2026 - February 2027	$174.844

Q. Has the Company met its commitment to spending the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, U-21389, U-21585, and U-21870?

A. Yes, the Company has met its commitment to spend the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, U-21389, and U-21585. In the test period for Case No. U-21870 (May 2026 through April 2027), the Company plans to spend $186.684 million for its Line Clearing Program of which $164.446 has been authorized for collection in base rates. Figure 21 below outlines each MPSC case number authorized spend and actual spend. Over this timeframe, the Company invested $29.741 million in its Line Clearing Program above the authorized spend amounts in the defined test periods.

[11] Includes wildfire risk mitigation expenditures.

FIGURE 21
LINE CLEARING PROGRAM SPEND AUTHORIZED TO ACTUAL

MPSC Case No.	Timeframe	Authorized Spend ($M)	Actual Spend ($M)	Difference in Authorized Spend and Actual Spend ($M)
U-20697	January 2021 - December 2021	$84.000	$86.567	$2.567
U-20963	January 2022 - December 2022	$93.959	$102.003	$8.044
U-21224	January 2023 - December 2023	$100.030	$109.093	$9.063
U-21389	March 2024 - February 2025	$118.890	$119.189	$0.299
U-21585	March 2025 - February 2026	$125.408[12]	$135.176[12]	$9.768
U-21870	May 2026 - April 2027	$186.684	$186.684	$0.000
Total	January 2021 - February 2026	$708.971	$738.712	$29.741

Q. How did the Company project spending for the 2026 calendar year, the 2027 calendar year, and the test period (May 1, 2027 through April 30, 2028)?

A. The 2026 calendar year spending projection in the Company's 2025 Electric Rate Case No. U-21870 totaled $164.953 million for both LVD and HVD programs; in this case, this is updated to $165.010 to accommodate more line clearing miles in the HVD work plan. The Company sought an increase for the 2026 calendar year based on the commencement of its LVD ramp-up strategy to a five-year clearing cycle and performing more aggressive line clearing on targeted three phase primary lines. For this case, projected 2027 calendar year spending was derived from operational intelligence by Forestry Operation's Director, Manager of Strategic Planning and Performance, and other staff members. Values presented in Exhibit A-186 (SES-1) are the Forestry Operation team's projections, informed by historical costs per mile cleared, current system work estimates, crew availability and work schedules, and other factors to maintain clearing on the HVD system

[12] Includes wildfire risk mitigation expenditures.

at current level and to reduce the clearing cycle on LVD. The test period (May 1, 2027 through April 30, 2028) presented in Exhibit A-186 (SES-1) includes eight months (8/12th) of the 2027 calendar year and four months (4/12th) of the 2028 calendar year to create the 12-month period.

Q. For the test year, what will happen to dollars remaining if the HVD work plan is completed under budget?

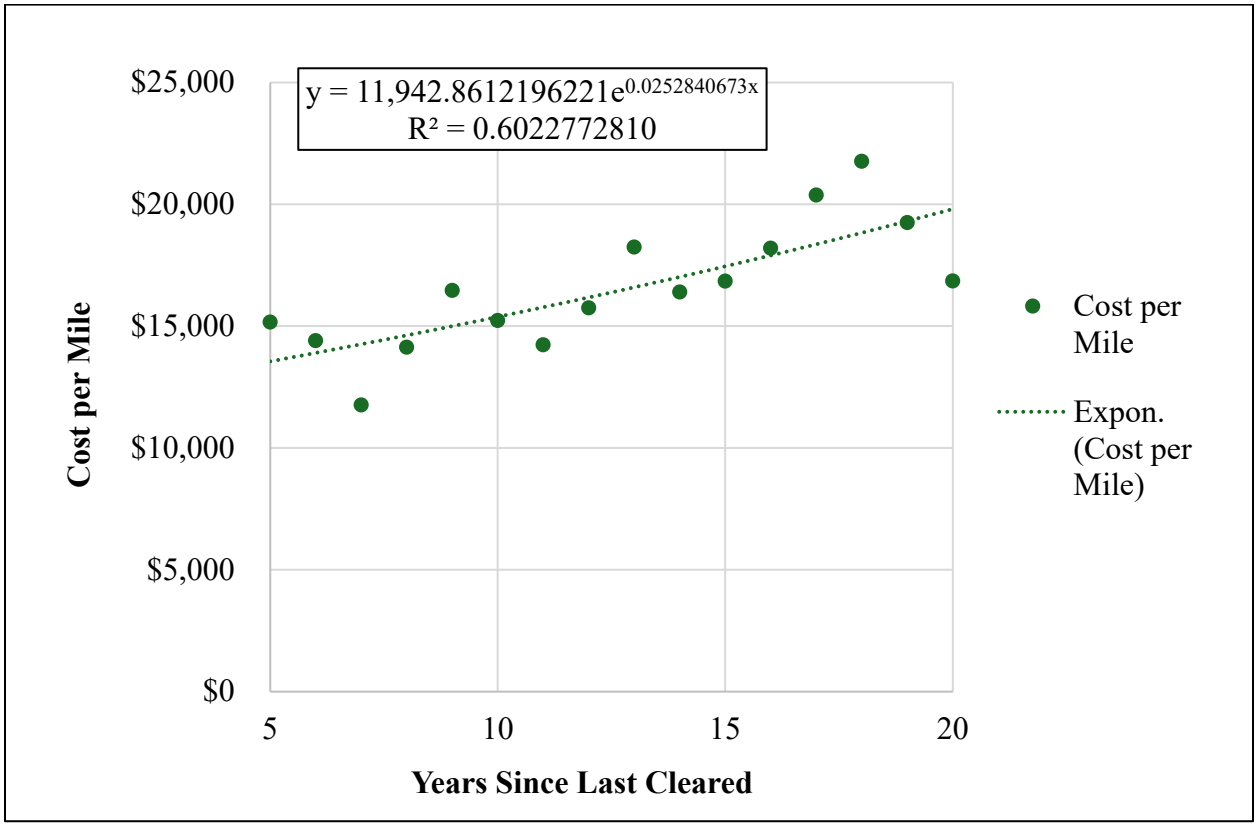
A. If the HVD work plan is completed under budget, any remaining dollars for the test year will be allocated to the LVD system to support the Company's strategy of attaining a five-year cycle by the end of the 2030-2031 test period while still maintaining the HVD system on its four-year cycle.

Q. Does a shorter clearing cycle reduce the average cost per line mile to clear circuits?

A. Yes, the Company's data supports that a shorter period of time between line clearing on circuits results in a lower average cost per line mile. Longer clearing cycles result in more complex clearing work and require the removal of more biomass to achieve clearance to conductors, as the vegetation has had more time to grow between clearings. To inform its expense projections, the Company considered lower costs per mile to maintain circuits on a shorter cycle. Figure 22 below shows the relationship between contractor full circuit clearing costs per mile and the number of years between clearings utilizing full circuit clearing data from 2021 through 2025 on circuits last cleared 5 to 20 years earlier, with all costs inflated to 2025 dollars. It is important to note that there is more available data on longer durations between clearings as the Company has been working to reduce the LVD backlog. Some data exists for shorter durations between clearings to inform this trend and more will become available as the Company's strategy includes performing clearing on

more cycle circuits, preventing cycle circuits from becoming backlog circuits. This data will continue to be refined, and expense projections updated accordingly.

FIGURE 22
2021-2025 CONTRACTOR FULL CIRCUIT CLEARING COST PER LVD MILE BASED ON YEARS SINCE LAST CLEARED



Q. What are the historical unit costs for the Company's O&M clearing work in LVD Line Clearing?

A. Unit costs over the last five years are provided in Figure 23 below:

FIGURE 23
LVD LINE CLEARING UNIT COSTS

Description	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025
O&M Cleared Miles	5,279	6,388	6,365	6,030	6,790
O&M Expense ($M)	$75.83	$91.02	$97.79	$99.49	$125.50
$/line mile	$14,363	$14,248	$15,364	$16,500	$18,485

Q. Please explain the increase in unit costs in recent years.

A. The greatest impact on unit costs for 2021 and 2022 was the ramp-up with many new contractor employees and vendors new to the utility line clearing business. New employees are less productive until their skill levels develop to optimal performance while maintaining safety protocols. Secondly, the addition of new Michigan-based vendors, all of which are smaller scale operations compared to the large nationwide utility line clearing contractors, increased unit costs as their business cost structures are much different than the nationwide vendors. In time, as these Michigan-based vendors grow, their cost structures will align more closely to the nationwide vendors and unit costs will decrease.

The greatest impact on unit costs for 2023 was a higher percentage of more expensive supplemental vendor crews compared to base crews and a higher percentage of backlog circuit miles cleared than anticipated; these additional backlog circuit miles were selected and added with the $8.0 million in one-time funding from MPSC Case No. U-21332.

The greatest impact on unit costs for 2024 was new line clearing contracts executed in the second quarter of 2024. The Company experienced an approximate 12% increase above inflation in the base rates for line clearing contractors for 2024 when these new contracts went into effect.

The greatest impacts on unit costs for 2025 were per diems for out-of-state crews, increased crew overtime to achieve the planned line clearing miles, and canopy removal on targeted three phase LVD primary lines, as discussed earlier in my testimony.

Q. How does the Company mitigate contractor costs while ensuring the reliability benefits of line clearing are realized?

A. The Company applies several operational and strategic tactics to mitigate contractor costs. Operationally, it relies on in-state crews as much as practical, as out-of-state crews may require a per diem expense and/or have higher rates. Additionally, it manages crew hours and limits more costly overtime when possible, while balancing service restoration support and capital clearing project timelines. At a local level, crew efficiency is monitored closely and billable versus non-billable labor and equipment time is scrutinized for accuracy and opportunities for improvement. Strategically, line clearing work is bundled and sequenced when it proves more efficient for productivity, such as: (i) timing urban line clearing work within seasonal weight restrictions; (ii) timing line clearing work in areas of known environmental constraints outside of the constraint window; and (iii) targeting line clearing work overlapping wet areas with times of year the ground is frozen or dry. Company Forestry management meets quarterly with management of each vendor to review data trends including productivity and cost metrics to target, collaborating on intervention methods.

Realizing the reliability benefits of line clearing is of utmost importance to the Company and its electric customers. This starts with having the right work plan, as informed by the forestry model that is built into the forestry workplan selection tool. The work plan is sequenced to target completion of the right work at the right time, prioritizing reliability and safety benefits, and utilizing the most current circuit reliability performance data. Line clearing contractors perform the work while productivity and efficiency are monitored. Finally, as described earlier in my testimony, the Company performs a robust

post-work review process for scheduled O&M projects, ensuring the work is completed to standard. This framework is how the Company delivers value for its customers through the Line Clearing Program.

Q. Does the Company request to recover the entirety of its LVD Line Clearing O&M spending in the test period through base rates?

A. No, it does not.

Q. Is the Company proposing an alternate mechanism to fund LVD Line Clearing O&M in the test period?

A. Yes, the Company is proposing continuation of the deferred accounting mechanism approved by the Commission in Case No. U-21870 for calendar years 2027 and 2028 and the projected test period. The mechanism permits the Company to defer line clearing expenditures that exceed approved baseline expenditures. The Company is requesting that, in addition to the "ramp-up" funding deferral approved in Case No. U-21870, the Commission approve "ramp-up" funding deferral for calendar years 2027 and 2028 in the amounts identified in Exhibit A-186 (SES-1), columns (j and k, respectively), line 34. The corresponding projected test year amount is shown on the same line in column (o). This proposed deferred accounting funding mechanism is discussed in further detail in Company witness Patton's testimony on page 35, line 1, through page 36, line 4.

RESOURCING PLAN FOR THE LINE CLEARING PROGRAM

Q. Does the Company currently have the personnel and other resources to complete the projected HVD line clearing work if the Commission approves the requested spending level?

A. Yes, the Company currently has the resources in place to maintain the HVD system on a four-year clearing cycle.

Q. Does the Company currently have the contracts and resourcing plans in place to increase its personnel and other resources to complete the projected LVD line clearing work if the Commission approves the requested spending level?

A. Yes. At the time of this filing, the Company has conducted resource planning activities with its contractors and has adequate contracts in place to secure the personnel and other resources required to execute the full requested spending level. The Company has been able to secure sufficient line clearing crews to support the increasing workload of line clearing miles, and is confident in successful procurement of additional crews. Figure 24 below outlines actual crewing from 2021 through 2025 and the projected crewing plan for 2026 through 2031.

FIGURE 24
HVD AND LVD LINE CLEARING CREWING

		HVD	LVD		
Calendar Year	**Data Type**	**Local Crews**	**Local Crews**	**Out-of-State Crews**	**Total Crews**
2021	Actual	42	299	0	341
2022	Actual	38	334	0	372
2023	Actual	38	348	0	386
2024	Actual	38	347	0	385
2025	Actual	38	383	0	421
2026	Projected	38	420	80	538
2027	Projected	38	432	113	583
2028	Projected	38	432	155	625
2029	Projected	38	435	155	628
2030	Projected	38	435	155	628
2031	Projected	38	465	30	533

Q. How does the Company plan to ramp up its LVD Line Clearing spending and full circuit clearing work for the 2027 calendar year and test period?

A. The projected 2027 calendar year increase in O&M expense and LVD full circuit clearing miles is provided in Figure 15 above and in Exhibit A-186 (SES-1) for the test period. As Figure 15 indicates, in the 2027 calendar year, the Company projects to clear 10,889 miles in its full circuit clearing subprogram, which is 2,998 more miles (38% higher) than the projected 2026 full circuit clearing mileage. The Company projects that it will need 45 additional contractor line clearing crews above the 2026 crewing level to accomplish this plan in the 2027 calendar year. In partnership with its current vendors under terms established with new contracts executed in the second quarter of 2024, and through the engagement of supplemental vendors, the Company is confident it will meet this required crewing level.

Q. Does this conclude your direct testimony in this case?

A. Yes, this concludes my direct testimony.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Tax Director in the Company's Corporate Tax Department.

Q. Please briefly describe your educational background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's property accounting team. In 2013, I was appointed Property Tax Manager with the Company's corporate tax team. In 2019, I was promoted to Director of Corporate Tax and, in 2024, I moved into my current position as Director of Tax Research and Planning.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Director of Tax Research and Planning?

A. I am responsible for researching, developing, and implementing tax planning, process improvement, and tax technology strategies as well as managing the Company's long-term forecast of taxable income, tax deductions, tax credits, and federal and state cash tax payments. I am also responsible for tax planning opportunities associated with the

Company's property taxes, including matters concerning personal property, land, generating sites, and other real property located in approximately 1,500 taxing authorities.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322;
- Gas Rate Case No. U-20650;
- Electric Rate Case No. U-20697;
- Gas Rate Case No. U-21148;
- Electric Rate Case No. U-21224;
- Electric Rate Case No. U-21389;

- Gas Rate Case No. U-21490;
- Electric Rate Case No. U-21585;
- Gas Rate Case No. U-21806;
- Electric Rate Case No. U-21870; and
- Gas Rate Case No. U-21981.

Q. What is the purpose of your direct testimony in this proceeding?

A. First, my direct testimony supports the Company's request for two different state income tax items. These state income tax items include 1) authorization to defer for future recovery Michigan income tax expense currently provided as a benefit to customers in this case in the event the Company is unsuccessful in defending a state apportionment position challenged by the Michigan Department of Treasury ("Treasury"), and 2) authorization to collect Illinois state income tax expense from customers related to the Company having Midcontinent Independent System Operator, Inc. ("MISO") apportioned sales and nexus in Illinois as a result of increased employee activity in the state. My testimony also identifies the Property Tax Rate for the test year (12 months ending April 30, 2028) and explains how the rate was derived. Finally, I am also supporting the amount of test year excess deferred federal income taxes being returned to electric customers as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C proceeding, Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-193 (BJV-1) Development of the Property Tax Rate for the Test Year; and

Exhibit A-194 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

REGULATORY REQUESTS FOR STATE INCOME TAXES

Q. Please explain the Company's state income tax apportionment position and the status of the case currently being challenged by the Michigan Department of Treasury.

A. The Company requests Commission authorization to defer for future recovery Michigan income tax expense currently provided as a benefit to customers in this case if the Company is unsuccessful in defending the following state apportionment position being challenged by the Treasury.

Michigan's income tax law, Public Act 281 of 1967, requires corporations engaged in interstate operations to apportion their income using a formula, the numerator of which is sales in Michigan and the denominator of which is sales everywhere. The apportionment of sales from tangible personal property, including sales from electricity and gas, are included in the numerator if "the ultimate destination at the point that the property comes to rest" in Michigan.[1] The Company takes the position that a portion of the Company's wholesale electricity sales sourced into the MISO energy market have an ultimate destination outside of Michigan. Accordingly, the Company has calculated an apportionment percentage since tax year 2017 of approximately 87% for Michigan Corporate Income Tax ("MCIT") purposes, with the remaining 13% resulting in an apportionment of sales to states other than Michigan within the MISO footprint.

[1] MCL 206.665(1)(a)

In 3Q 2017, CMS Energy Corporation[2] filed amended MCIT returns using this apportionment methodology for tax years 2013 through 2016 seeking a total refund of approximately $7.8 million. On October 29, 2018, Treasury denied the refund claim. On August 29, 2019, the Company filed a petition for refund with the Michigan Tax Tribunal. On February 13, 2025, the Company received an adverse decision from the Michigan Tax Tribunal and, on March 5, 2025, filed for leave to the Michigan Court of Appeals. The Company presented the case before the Michigan Court of Appeals on February 6, 2026 and received an adverse opinion on February 17, 2026. The Company is currently preparing an application for leave to the Michigan Supreme Court.

Q. How do customers benefit from the Company's apportionment methodology in this case?

A. Company witness Hannah L. Patton's Exhibit A-13 (HLP-46), Schedule C-9 calculates state income tax expense for the projected test period ending April 30, 2028. Total state income tax expense is comprised of current state income taxes on line 14 and deferred state income taxes on line 15. The Company's calculation of state income tax expense currently utilizes the Company's MISO-apportioned Michigan income tax rate of 5.24% (6% statutory MCIT rate at 87.3333% apportionment) as noted in lines 14 and 15 of the exhibit rather than Michigan's statutory corporate income tax rate of 6%. At the MISO-apportioned state income tax rate of 5.24%, customers in this case would pay approximately $36.041 million in state income tax expense compared to $40.558 million at the statutory state income tax rate of 6%. The Company's apportionment methodology

[2] CMS Energy Corporation is the parent company of the unitary filing of which Consumers Energy Company is included.

provides electric customers with a $4.517 million benefit in state income tax expense. Since state income taxes are also deductible for federal income tax purposes, the state income tax benefit included in this case, net of a 21% federal deduction, is $3.568 million.

Q. Have customers benefited from the lower MISO-apportioned MCIT rate prior to this case?

A. Yes. Since the Company first lowered the MCIT rate to reflect the lower Michigan apportionment in Case No. U-20314, the Company's as-filed state income tax expense has reflected approximately $29 million of MCIT tax benefit, or approximately $23 million net of a 21% federal deduction.

Q. Given the adverse decisions at the Michigan Tax Tribunal and the Michigan Court of Appeals, why is the Company continuing to provide the apportioned state tax benefit to customers in this case?

A. The Company's position is that it should prevail under the plain language of the statute, which not only allows for, but was written, to consider the complexity of intra-state electric and gas wholesale markets such as the MISO energy market where the "ultimate destination" electricity "comes to rest" may not be at a transmission interconnection just outside the fence from a Michigan electric generating facility. In short, the Company maintains its position that the courts failed to give effect to the legislature's sourcing framework despite lawmakers express decision to treat electricity the same as all other tangible personal property where Michigan manufacturers and distributors transact goods through in-state hubs before reaching out-of-state customers. Further, the Company's position also entails customers should be entitled to the financial benefit afforded under a

favorable apportionment methodology until such time as the Michigan Supreme Court upholds a final decision.

Q. If the Company fails to persuade the Michigan Supreme Court to overturn the prior adverse decisions, what is your request of the Commission?

A. If the Company is unsuccessful in persuading the Michigan Supreme Court to overturn the adverse decision, the Company requests the ability to defer the additional state tax expense not currently charged to customers as a result of the favorable MISO-apportionment methodology. For this case during the projected test period, we expect that amount to be approximately $3.5 million as outlined earlier in my testimony.

Q. Have there been any other state income tax developments that impact the amount of non-Michigan state income tax expense recorded by the Company.

A. Yes. The Company has also recorded increased non-Michigan income tax expense attributable to its sales to MISO in Illinois. Under the MISO sales apportionment methodology described earlier in my testimony, the Company has calculated an apportionment percentage of approximately 1.1% for Illinois state income tax purposes. With the apportioned sales and an increased employee presence causing nexus in the state, the Company has determined it is necessary to record annual Illinois state income tax expense on a prospective basis.

Q. Can you describe nexus and how it creates additional out-of-state tax liability for the Company?

A. Nexus arises when a taxpayer has a physical or economic presence with a state. Generally, the Company invests in assets that are physically located in Michigan and focuses on procuring products and services from Michigan-based vendors. But the reality is we serve

Michigan customers as a Midwest energy company and there are prudent business decisions for venturing outside of Michigan. For instance, the Company's current request for proposal seeking to secure competitive bids for clean energy and capacity is open to power purchase agreements, build transfer agreements, and development acquisition agreements from participants in the Pennsylvania – New Jersey - Maryland Interconnection ("PJM") and MISO energy markets, including each of MISO's zones 1 – 7. In addition to clean energy acquisitions, the Company's employees can create physical nexus in other states by visiting material vendors, meeting with service providers, or attending conferences or training seminars. Coupled with MISO apportioned sales into a regional energy market, physical nexus caused by the presence of employees in a state can result in additional state income tax liability.

Q. Please describe the amount of Illinois state income tax expense that would be applicable to electric customers in this case and indicate whether the Company has included this amount in this filing.

A. Using Company witness Patton's Exhibit A-13 (HLP-46), Schedule C-9 calculating MCIT expense as a proxy, the Illinois state income tax expense, based on a 1.1% apportionment and 9.5% tax rate, would increase the Company's as filed state income tax expense by $0.565 million, or approximately $0.450 million net of a 21% federal deduction. Currently, this amount is not included in the Company's pre-filed state income tax expense presented in this case.

Q. What is your request of the Commission with respect to the Illinois state income taxes?

A. Given customers are benefiting from lower MISO-apportioned MCIT expense as described previously in my testimony and the Company has presented evidence supporting prudent, customer-focused reasons for having a physical presence in Illinois, the Company requests Commission approval to recover Illinois state income tax expense from customers in future rate cases.

Development of the Property Tax Rate for the Test Year

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-193 (BJV-1), page 1, line 17, the Property Tax Rate for the test year is 0.013560205.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the electric business was calculated using the Company's prorated Electric Property Tax Expense, shown on Exhibit A-193 (BJV-1), page 1, line 11, divided by the total of the 2027 Estimated Year-End Plant-in-Service, shown on Exhibit A-193 (BJV-1), page 1, line 12, plus one-half of the 2027 Estimated Construction Work-in-Progress, shown on Exhibit A-193 (BJV-1), page 1, line 15.

Q. What is included in the Electric Property Taxes Paid – 2027 Estimate on Exhibit A-193 (BJV-1), page 1, line 1?

A. The 2027 taxes paid by Consumers Energy of $312.1 million on behalf of the electric portion of the business represents the estimated property taxes to be paid in 2027.

Q. What is included in the Electric Property Taxes on 2027 Plant Investment on Exhibit A-193 (BJV-1), page 1, line 2?

A. The $32.1 million increase is the estimated property taxes on the 2027 net additions that will be included in the 2028 property tax liability. This is calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 49.8815 to obtain the estimated tax amount. This calculation is shown on Exhibit A-193 (BJV-1), page 2, line 9.

Q. What is included in the 2028 Fossil Plant Valuation Tax Reduction on Exhibit A-193 (BJV-1), page 1, line 3?

A. The $0.1 million decrease reflects a reduction in property taxes associated with the D.E. Karn Plant (Units 3-4). The reduction in property taxes is the result of successful negotiations with the local unit of government over the taxable value of the Company's fossil fuel-fired electric generating facilities.

Q. What is included in the Electric Property Taxes on Real Property Taxable Value Increases on Exhibit A-193 (BJV-1), page 1, line 4?

A. The $1.2 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2028, the Company's property tax model assumes a CPI rate of 2.2%. This calculation is shown on Exhibit A-193 (BJV-1), page 3.

Q. What is the result of including the Electric Property Taxes on 2027 Plant Investment, 2028 Fossil Plant Valuation Tax Reduction, and Electric Property Taxes on Real Property Taxable Value Increase on the estimated 2028 property tax amount paid by the electric business?

A. The result of including these additional items is an estimated 2028 property tax amount to be paid for the electric business of $345.3 million, as shown on Exhibit A-193 (BJV-1), page 1, line 5.

Q. Does the amount on Exhibit A-193 (BJV-1), page 1, line 6, include property tax payments for pollution control equipment or computer software, such as SAP?

A. No, as pollution control equipment and computer software are exempt under MCL 324.5904(1) and MCL 211.9d, the estimate of 2028 property tax to be paid on line 5 does not include property taxes associated with these items.

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2027 estimated electric property tax payments for Consumers Energy is added to the 2028 estimated electric payments since that amount will be expensed in 2028, while subtracting 50.0% of the 2028 estimated electric payments that will be expensed in 2029, arriving at a total 2028 electric property tax expense of $328.7 million as shown on Exhibit A-193 (BJV-1), page 1, line 8.

Q. What is the next step in calculating the tax rate for the test year?

A. For the test year, property tax expense was prorated for the period of May 1, 2027 through April 30, 2028 using a monthly budgeted sales percentage applied to the 2027 and 2028 estimated annual property tax expense amounts. The result of factoring property tax

expense monthly for the test period is a prorated Electric Property Tax Expense of $301.8 million, as shown on Exhibit A-193 (BJV-1), page 1, line 11. The prorated Electric Property Tax Expense for the test year is divided by the 2027 Estimated Year-End Plant-in-Service plus one-half of 2027 Estimated Construction Work-in-Progress to arrive at a property tax rate of 0.013560205.

Q. On March 21, 2025, in Case No. U-21585, the Commission supported the Administrative Law Judge's recommendation that, "Consumers continue to provide a list of pending tax assessment litigation cases and negotiations in rate case filings going forward." Does the Company have any current property tax litigation?

A. No. The Company is not currently involved in property tax litigation at this time.

Amortization of Excess Deferred Federal Income Taxes for the Test Year

Q. On September 26, 2019, in Case No. U-20309, the Commission issued an Order in the Company's Calculation C case. What specific issues did the September 26, 2019 Order address?

A. The Commission's September 26, 2019 Order in the Company's Calculation C case authorized the amount and time period under which the Company will refund to electric customers $1,174,181,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21224, the Commission approved an adjustment to reduce this amount by $4,168,278 to correct an overstatement of the TCJA remeasurement. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the Average Rate Assumption Method ("ARAM"); (ii) Non-Protected plant balances amortized over 27 years; and (iii) Unprotected non-plant

balances amortized over 10 years. Exhibit A-194 (BJV-2), page 2, referenced as Exhibit A-5 (SBM-3) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. What additional amount of excess deferred taxes related to the TCJA has the Company proposed to refund to customers in this case?

A. As shown on Exhibit A-194 (BJV-2), page 1, line 22, the Company has proposed to charge an additional $2,104,000 of excess deferred taxes ($2,822,000 of regulatory asset after gross-up for taxes) in this case. This amount represents the Company's regulatory asset recorded as of year-end 2023 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates. The Company's most recently filed report to the Case No. U-20309 docket, which calculates the $2,822,000 regulatory asset balance, is included as Exhibit A-194 (BJV-2), page 3.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the additional amount described above, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-194 (BJV-2), page 1, provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $32,506,000 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Hannah L. Patton's Exhibit A-13 (HLP-45), Schedule C-8, lines 45, 46, and 47 as TCJA Amortization – ARAM, TCJA – Non-ARAM, and TCJA Tracker.

Q. Are the excess deferred federal income tax amounts refunded to electric customers in the test year estimates or actuals?

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in Case No. U-20309 by March 31st of each year.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

MARK E. WITTBRODT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Q. Please state your name and business address.

A. My name is Mark E. Wittbrodt, and my business address is 4141 Wilder Road, Bay City, Michigan 48706.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently a Senior Strategy Manager of Electric Asset Strategy in Commercial Operations and Planning at Consumers Energy. I began my employment with the Company in August 2006 as a System Owner (Reliability Engineer) at the D.E. Karn Plant ("Karn"), where I was responsible for rotating equipment. In April 2013, I was appointed Engineering Lead for the Karn Site, overseeing all Reliability Engineers and subject matter experts. In November 2014, I assumed the role of Principal Engineering Manager for the east side of Michigan, with responsibility for the reliability engineers and subject matter experts at the Karn and Jackson generating stations. In January 2015, I was assigned Principal Engineering Manager for the Equipment Services Department, Rotating Equipment. In this role, I oversaw rotating equipment engineering support for all Consumers Energy electric generating facilities, including coal, gas, pumped storage, river hydro, and renewable energy assets. This organization consisted of subject matter expert engineers supporting rotating equipment across the Company's generation fleet. In April 2019, I was named Asset Strategy Manager for the coal fleet, with responsibility for developing the long-term financial and outage plans for those assets. In April 2020, I was appointed Senior Strategy Manager for all Consumers Energy generating assets.

Q. What are your responsibilities as Senior Strategy Manager of Electric Asset Strategy?

A. My responsibilities as Senior Strategy Manager of Electric Asset Strategy include the oversight of Coal, Gas, Pumped Storage, River Hydro, Wind, Solar, Battery Storage, and new Clean Energy Initiatives. In this role, I develop the Long Term Financial and Outage Plan for the entire fleet. In addition, it requires oversight of the day-to-day or annual budgets, managing risks, and ensuring the budgets come in on target. Historically, I have provided support to the Electric Rate Case witnesses for testimony, rebuttals, and reconciliation throughout the process. My overall mission is to drive risk-informed, strategically aligned decisions across the Electric Supply portfolio by integrating long-term planning, outage strategy, and asset reliability – all with a clear focus on delivering customer value.

Q. What is your formal educational experience?

A. I received a Bachelor of Science Degree in Civil/Environmental Engineering in 1998 from Michigan Technological University. In 2002, I received a Master of Business and Science from Rensselaer Polytechnic Institute in New York. In 2018, I received my Masters in PMP as a Project Management Professional from George Washington University.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Generation Department ("Generation") requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy's oil-, and gas-fired generation assets, and its hydroelectric, renewable generation assets, including their projected retirement dates;

- Support the Company's generation asset strategy to focus continued investment in those generating units (Zeeland Generating Station ("Zeeland Plant," "ZGS," or "Zeeland"), Covert Generating Facility ("Covert Plant," "CGS," or "Covert"), and Jackson Generating Station ("Jackson Plant," "JGS," or "Jackson")) which provide the most long-term economic benefit for customers;

- Present the actual 2025 coal ash disposal costs for Karn Units 1 and 2 and the Classic 7;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate ("ROR") projections for oil- and gas-fired peaking generation, and hydroelectric power generation, for the projected test year ending April 30, 2028;

- Support the reasonableness and prudence of the capital expenditures for oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2025, the 16-month bridge period beginning January 1, 2026 and ending April 30, 2027, and the projected test year ending April 30, 2028;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2025 and the projected test year ending April 30, 2028;

- Support the reasonableness and prudence of the O&M expenses for the Karn Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2025;

- Support the reasonableness and prudence of the O&M expenses for the J.H. Campbell ("Campbell") Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2025, and the 16-month bridge period beginning January 1, 2026 and ending April 30, 2027;[1] and

- Describe the environmental regulations with which the Company's electric generating fleet must comply.

[1] On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 ("DOE Order") requiring the Company to "take all measures necessary to ensure that the Campbell Plan is available to operate" through August 21, 2025. As of the date this testimony is filed, these 90-day orders have continued, and are expected to continue through the test year.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Joshua W. Hahn's testimony supports the Power Supply Cost Recovery ("PSCR") costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-195 (MEW-1) and the generating unit availability projections in Exhibit A-196 (MEW-2). Company witness Hahn also supports the capacity value of the Company's generation assets for the seasonal construct in the Midcontinent Independent System Operator, Inc. ("MISO") Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Hannah L. Patton supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at Karn and Campbell sites in her direct testimony.

Company witness Heidi J. Myers supports the continued deferral of the revenue requirement for river hydroelectric generating plant ("River Hydro") proposed O&M deferral for River Hydro in her direct testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-195 (MEW-1)		Generating Unit Periodic Outages;
Exhibit A-196 (MEW-2)		Generating Unit Availability Projections;
Exhibit A-12 (MEW-3)	Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2025 through April 2028;

Exhibit A-197 (MEW-4)	Summary of the Generation O&M Expense for the Historic Year (2025) and Test Year ending April 30, 2028;
Exhibit A-198 (MEW-5)	Actual Coal Ash Disposal Plan Expenditures.
Exhibit A-199 (MEW-6)	Covert LCI SFC Replacement Concept Approval;
Exhibit A-200 (MEW-7)	Covert Site Spare GSU Concept Approvals;
Exhibit A-201 (MEW-8)	Covert Netmation Operating System Concept Approval;
Exhibit A-202 (MEW-9)	Covert Units 1 through 3 DCS Evergreen Concept Approval;
Exhibit A-203 (MEW-10)-CONF	Covert Plant LTSA (Confidential);
Exhibit A-204 (MEW-11)	Covert Units 1 through 3 NERC Relay Replacement Concept Approval;
Exhibit A-205 (MEW-12)	Covert Units 1 through 3 Circulating Water Pump Replacement Concept Approval;
Exhibit A-206 (MEW-13)	Covert MS Tee Header Replacement Unit 1 and 3 Concept Approval;
Exhibit A-207 (MEW-14)	Covert Plant Replace Sulfuric Hypo and Building Concept Approval;
Exhibit A-208 (MEW-15)	Karn Unit 3 & 4 Combustion Air Heater Replacement Concept Approval;
Exhibit A-209 (MEW-16)	Karn Unit 3 & 4 Ductwork Expansion Joint Replacement Concept Approval;
Exhibit A-210 (MEW-17)	Karn 4 Post-Transformer Fire Remediation Concept Approval;
Exhibit A-211 (MEW-18)	Karn Unit 4 ID Fan Inlet Damper Replacement Concept Approval;

Exhibit A-212 (MEW-19)	Zeeland Phase 2 Gas Turbine AGP Replacement and AFS Concept Approval;
Exhibit A-213 (MEW-20)	Zeeland Phase 2 Turbine Replacement Concept Approval;
Exhibit A-214 (MEW-21)	Zeeland Purchase of Site Spare GSU Concept Approval;
Exhibit A-215 (MEW-22)-CONF	Zeeland Plant GE LTSA (Confidential);
Exhibit A-216 (MEW-23)	Zeeland Ph I & II High Recovery Gas Valves Concept Approval;
Exhibit A-217 (MEW-24)	Zeeland 2C Field Exchange and Generator Major Overhaul Concept Approval;
Exhibit A-218 (MEW-25)	Zeeland MS & Hot Reheat Isolation Valve Replacement Concept Approval;
Exhibit A-219 (MEW-26)-CONF	Jackson Plant GE LTSA (Confidential);
Exhibit A-220 (MEW-27)-CONF	Jackson Plant GE LTSA Amendment 1 dated February 28, 2002 (Confidential);
Exhibit A-221 (MEW-28)-CONF	Jackson Plant GE LTSA Amendment 2 dated November 17, 2017 (Confidential);
Exhibit A-222 (MEW-29)-CONF	Jackson Plant GE LTSA Amendment 3 dated December 17, 2018 (Confidential);
Exhibit A-223 (MEW-30)-CONF	Jackson Plant GE LTSA Assignment Agreement (Confidential);
Exhibit A-224 (MEW-31)	Jackson GSU Transformer Site Spare Concept Approval;
Exhibit A-225 (MEW-32)	Jackson Variable Inlet Guide Vain Concept Approval;

Exhibit A-226 (MEW-33)	Jackson Unit 7 GT Rotor Replacement Concept Approval;
Exhibit A-227 (MEW-34)	Jackson Main and Aux Cooling Tower Rebuild Concept Approval;
Exhibit A-228 (MEW-35)	LPS DCS Control Relay Concept Approval;
Exhibit A-229 (MEW-36)-CONF	LPS Unit 1 Pony Motor Replacement Concept Approval (Confidential);
Exhibit A-230 (MEW-37)-CONF	LPS Units 2 & 4 Head Cover and Bottom Ring Replacement Concept Approval (Confidential);
Exhibit A-231 (MEW-38)	LPS Administration Building Concept Approval;
Exhibit A-232 (MEW-39)	LPS Replace 480V DLC Concept Approval;
Exhibit A-233 (MEW-40)	LPS Governor Replacement Concept Approval;
Exhibit A-234 (MEW-41)	LPS Intake Gate and Gate House Concept Approval;
Exhibit A-235 (MEW-42)	LPS Life Cycle Management Concept Approval; and
Exhibit A-236 (MEW-43)	Emergent Reliability Funding 2025 Detail.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, its generating asset projected performance metrics, and decommissioning and coal ash disposal expenses. Included in this section is a discussion on the status of the Company's

River Hydro strategy and its projected impact on the Company's cost projections. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives and the Company's proposal for River Hydro O&M expense.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of February 24, 2026, the Company's total projected owned generation assets for the 2026/2027 Planning Year had a Generator Verification Test Capacity ("GVTC") of 4,874.8 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
OIL OR GAS FIRED					
Covert	Covert, MI	2004	22	2040	1092
DE Karn 3	Essexville, MI	1975	51	2031	588
DE Karn 4	Essexville, MI	1977	49	2031	587
Zeeland CC	Zeeland, MI	2002	24	2041	532
Zeeland 1A	Zeeland, MI	2002	24	2041	185
Zeeland 1B	Zeeland, MI	2002	24	2041	184
Jackson	Jackson, MI	2002	24	2041	532
HYDROELECTRIC					
Alcona	Alcona County, MI	1924	102	n/a	3
Allegan	Allegan County, MI	1936	90	n/a	1
Cooke	Iosco County, MI	1911	115	n/a	7
Croton	Newaygo County, MI	1907	119	n/a	2
Five Channels	Iosco County, MI	1912	114	n/a	6
Foote	Iosco County, MI	1918	108	n/a	3
Hardy	Newaygo County, MI	1931	95	n/a	34
Hodenpyl	Wexford County, MI	1925	101	n/a	4
Loud	Iosco County, MI	1913	113	n/a	5
Mio	Oscoda County, MI	1916	110	n/a	1
Rogers	Mecosta County, MI	1906	120	n/a	2
Tippy	Manistee County, MI	1918	108	n/a	6
Webber	Ionia County, MI	1907	119	n/a	1
RENEWABLES					
Lake Winds	Mason County, MI	2012	14	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	12	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	8	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	8	2048	
Crescent Wind	Jonesville, MI	2021	5	2051	166
Gratiot Farms Wind	Alma, MI	2021	5	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	2	2054	200
Solar Gardens- GVSU	Grand Rapids, MI	2016	10	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	10	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	5	2051	0.5
Circuit West	Grand Rapids, MI	2019	7	2049	0.5
Muskegon Solar	Muskegon, MI	2025	1	2060	250.0
ENERGY STORAGE					
Ludington Units 1-6**	Ludington, MI	1973	53	2069	936 (owned share)

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("LPS" or "Ludington") Units 1 through 6?

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 936 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous Electric Rate Case, Case No. U-21870?

A. Yes. On May 23, 2025, the DOE Order requiring the Company to "take all measures necessary to ensure that the Campbell Plant is available to operate" through August 21, 2025. When the DOE Order was about to expire, the DOE issued a 90-day extension. As of the date this testimony is filed, these 90-day orders have continued, and are likely to continue through the test year.

Q. How will the Company continue to meet its load requirements once the Campbell units are able to retire?

A. The Settlement Agreement approved in the Company's 2021 Integrated Resource Plan ("IRP") reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn Units 3 and 4, and the addition of Zonal Resource Credits ("ZRCs") by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

Q. What capacity resources were identified through the one-time solicitation?

A. The IRP one-time solicitation resulted in the execution of three separate contracts totaling 400 MW of BESS projects. On January 12, 2024, the Company filed the Tibbits Energy Storage, LLC Power Purchase Agreement ("PPA"), a 100-MW battery storage project, which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years, with deliveries commencing on June 1, 2025, and an expected PPA termination date of

May 31, 2045. The IRP one-time solicitation also resulted in the Company's May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery storage energy project, which the MPSC approved in its August 22, 2024 Order. The Century Oaks Energy Storage LLC PPA also has a term of 20 years with deliveries expected to commence by May 31, 2026 and an expected PPA termination date of May 31, 2046. Finally, the IRP one-time solicitation resulted in the Company's September 27, 2024 filing of the Voyager Energy Storage LLC PPA, a 100-MW battery storage project, which the MPSC approved in its November 21, 2024 Order. The Voyager Energy Storage LLC PPA also has a term of 20 years, with deliveries expected to commence by May 31, 2028, with an expected PPA termination date of May 31, 2048. Each of these contracts were filed in Case No. U-21090.

Q. What other actions has the Company taken to ensure it has sufficient capacity to reliably serve its customers?

A. In addition to the 400 MW of BESS PPAs, the Company has executed several agreements with Midland Cogeneration Venture ("MCV") for short-term capacity measured in ZRCs. On November 21, 2024 in Case No. U-21666, the Company received MPSC approval of a contract for 100 ZRCs for the 2025, 2026, and 2027 planning years. On March 21, 2025, in Case No. U-21827, the Company received MPSC approval of a contract for 175 ZRCs for the 2025 and 2026 planning years. The contract was the result of a reverse capacity auction that was conducted by an independent administrator on July 18, 2024.

On December 29, 2023, Public Act ("PA") 235 ("PA 235"), also known as the Clean and Renewable Energy and Energy Waste Reduction Act, was established. PA 235 provided new clean energy standards for Michigan public utilities, and as a result, the 2024

Clean Request for Proposal ("RFP") was launched. Not only would the Clean RFP fulfill Voluntary Green Pricing ("VGP") obligations, it would also seek the additional capacity that was not filled during the one-time solicitation. The Clean RFP resulted in an additional 450 MW of BESS projects including Grand Basin Energy Storage (100 MW) with an expected commercial operation date ("COD") of May 31, 2027; Hackett Energy Storage (100 MW) with an expected COD of May 31, 2028; Lakeside Energy Storage (100 MW) with an expected COD of May 31, 2028; and Voyager II Energy Storage (150 MW) with an expected COD of May 31, 2028.

Additionally, on June 2, 2025, the Company launched the 2025 All-Source solicitation with independent administrator, Enel X. This All-Source solicitation sought up to 1,500 MW of clean generation resources to serve the Company's IRP, VGP, and Renewable Energy Plan ("REP"). Bids for the All-Source solicitation were due August 28, 2025, and results are in evaluation. A second All-Source Solicitation was launched in early 2026.

GENERATION ASSET STRATEGY

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on delivering safe, reliable, affordable, and clean energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs and REPs, as approved by the MPSC.

Q. How does the Company's generation asset strategy apply to the Company's various generating units?

A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those

generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations.

Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP and the Company's 2024 Amended REP, the Company will concentrate investment in new renewable energy resources and continue investment in the existing gas-fired units as this strategy is intended to provide substantial long-term customer benefit.. During 2025, the Company's Covert, Zeeland, and Jackson Plants produced over 69% of the net energy value ("NEV") and approximately 68% of the capacity value realized by the Company's electric generating fleet (excluding renewables). As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2025 net energy and capacity value by asset type:

FIGURE 1

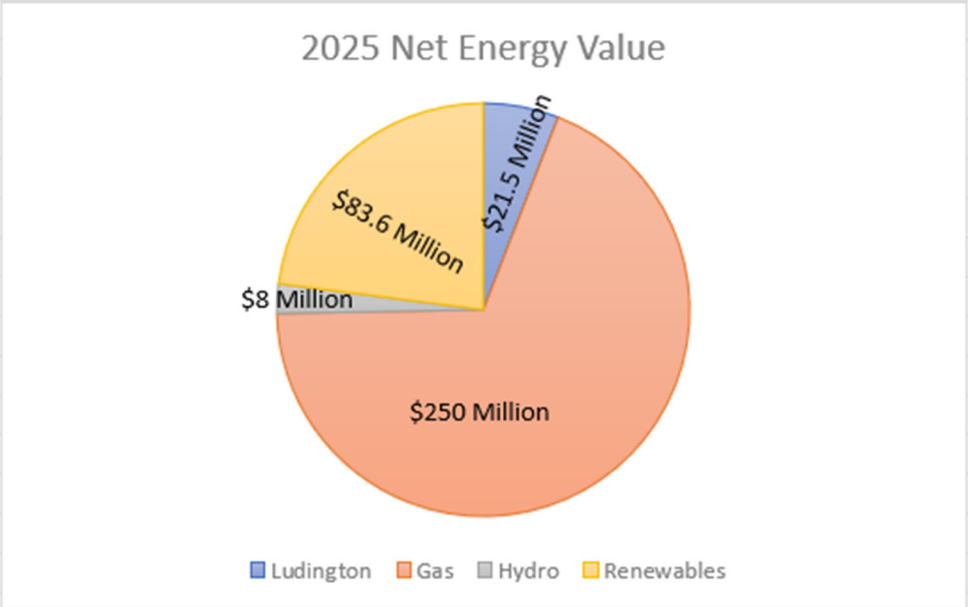
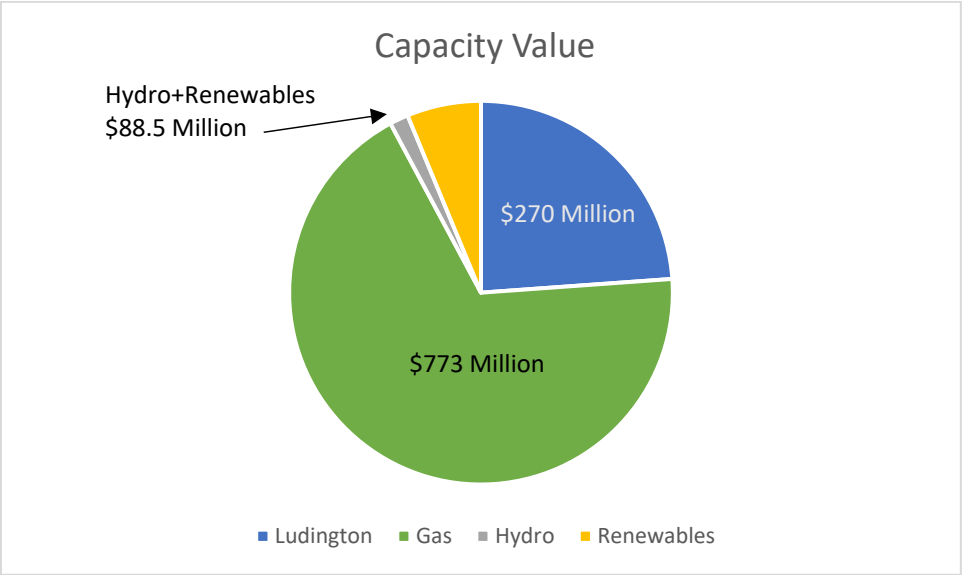


FIGURE 2



Q. How does the Company's generation asset strategy apply to the balance of the Company's generating units?

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value, and consistency with the Company's currently approved IRP expected retirement dates. The Company will continue to maintain its generating units, including the River Hydro facilities, to ensure safe and environmentally compliant operations. I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony describing projected generating unit availability.

Q. Has the Company's existing generation asset strategy changed as a result of the 2023 Michigan energy legislation?

A. Not materially. While PA 235 requires the Company to achieve a 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed to an aggressive transition

in its generation asset portfolio mix through its 2018 and 2021 IRPs. Pursuant to PA 235, the Company filed a REP amendment on November 15, 2024, which reflected its plans to comply with the new renewable energy laws.

With respect to the clean energy portion of the 2023 Michigan energy legislation, the details for the Company's compliance with the clean energy portfolio targets contained in that legislation will be reflected in the Company's PCA in its next IRP to be filed in 2026.

COAL ASH DISPOSAL

Q. Please describe the generating units for which the coal ash disposal costs are being incurred.

A. Karn Units 1 and 2 were approved for retirement in the Company's Commission-approved 2018 IRP (Case No. U-20165) and Campbell Units 1, 2, and 3 were approved for retirement in the Company's Commission-approved 2021 IRP (Case No. U-21090). As discussed earlier in this testimony, the Campbell Units' retirement is on hold due to the DOE Order. This retirement plan aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the transition to net zero carbon emissions by 2040, and meet customer needs with 60% renewable energy and 20% clean energy sources by 2035 with an increase to 40% clean by 2040.

The Classic 7 include three units at the J.R. Whiting ("Whiting") Generating Complex near Luna Pier; two units at the B.C. Cobb ("Cobb") Generating Plant in Muskegon; and two units at the Karn/J.C. Weadock ("Weadock") Generating Complex near Bay City. While all the Classic 7 units have been decommissioned, and the Cobb and

Whiting sites have since been divested, the Company still has ongoing responsibility for coal ash disposal costs, including groundwater monitoring.

Q. Please explain why the Company is presenting its actual 2025 Karn Units 1 and 2 coal ash disposal expenses in this proceeding.

A. As discussed in greater detail in Company witness Jon J. Koetje's testimony, the Commission issued an Order approving a settlement agreement in the Company's Electric Depreciation Case No. U-20849 ("U-20849 Settlement") providing for the recording of the Karn Units 1 and 2 decommissioning costs and the ash disposal costs for the Classic 7 and Karn Units 1 and 2 as spent, to a regulatory asset.

Q. Has the Company previously presented its plan for coal ash disposal costs for Karn Units 1 and 2 and the Classic 7?

A. Yes. The Company originally presented its plans for coal ash disposal costs for Karn Units 1 and 2 and for the Classic 7 in Case No. U-21224. The Commission-approved settlement agreement in that proceeding ("U-21224 Settlement") approved the Company's plans for coal ash disposal costs for Karn Units 1 and 2 and the Classic 7. Specifically, Paragraph 16 of the U-21224 Settlement stated:

> The Commission should approve the Company's proposed coal ash disposal costs for D.E. Karn Units 1 and 2 and the Classic 7. The costs associated with Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024.

Q. What were the Company's 2025 actual coal ash disposal costs?

A. Table 2 below illustrates the total actual 2025 expenditures for the Company's coal ash disposal plan.

Table 2

2025 Actual Coal Ash Disposal Costs ($000s)

Site	Actuals 2025
DE Karn	$ 16,313
JC Weadock	$ 2,427
BC Cobb	$ 842
JR Whiting	$ 69
JH Campbell	$ 12,677
Total	$ 32,341

Q. How were the Coal Ash Disposal Plan costs developed?

A. Remaining coal ash disposal costs consist of long-term groundwater monitoring at Karn, Weadock, Cobb, and Whiting as well as closure construction activities consisting of construction of a remedial response for the Karn Landfill, design and construction of a remedial response for the Karn closed Bottom Ash Pond, continued installation of a final cover system to close the Weadock Landfill, addressing remedial action plan ("RAP") requirements at Campbell Ponds B-K which consists of constructing treatment wetlands, monitoring groundwater, and harvesting the ash in B-K for subsequent beneficial use, and completing activities to satisfy the standards for closure certification of the Cobb Ash Ponds 0-8 and Bottom Ash Pond. Groundwater monitoring activities are required by state and federal regulations and are performed in accordance with detailed groundwater monitoring plans developed for each site in accordance with those regulations. The remedial response proposed for Karn Landfill is included in a RAP that has been approved by Department of Environment, Great Lakes, and Energy ("EGLE"). The final construction documentation and engineering drawings are currently under review by EGLE. The Weadock Landfill has a Closure Plan that was approved by EGLE facilitating

the accelerated closure completion of the landfill at a lower elevation. The Campbell B-K treatment wetlands and ash harvesting and beneficiation are part of the RAP that is being negotiated with EGLE, with approval expected in mid-2026. Removal of ash from the Cobb ash ponds was completed in accordance with an EGLE approved ash removal work-plan. EGLE provided written agreement upon completion of the removal activities in accordance with the approved work plan that the ash has been removed from the Cobb ash ponds. However, under the recently updated Resource Conservation and Recovery Act ("RCRA") rules, EGLE has indicated that the containment berms still in place at the site will need to be remediated in order to obtain final closure approval. The Company will work with the Cobb site owner to complete an updated site closure plan for approval by EGLE in 2026. The basis of costs for individual work scopes is provided below:

- All Sites Groundwater monitoring – these costs are based on existing third-party costs to collect samples from existing groundwater monitoring systems at each site and to analyze those samples at the laboratory. Costs also include evaluation of the data to determine the potential for a release from a coal ash disposal unit and any subsequent monitoring activities required to validate potential releases. These costs also include reporting of the results under state and federal requirements.

- Weadock Landfill closure scopes of work are well prescribed; the first two years of construction cost were based on contractor bids, and the remaining years are estimated based on similar work that was previously performed at the Karn Landfill. Site-specific items, including importation of additional fill to reach adequate closure grades, have been estimated by third parties and refined based on initial contractor bids. Design for relocating the electric distribution towers that are currently within the landfill footprint is complete with third parties providing cost estimates.

- Karn Landfill Remediation: As described above, this remedial activity has been proposed to the State as part of a RAP, which was accepted by the State in July 2023. The costs reflected represent the selection of a permeable barrier wall, the design of which was completed in 2024 and was approved by the State in early 2025. The construction of the permeable barrier wall was completed in

late 2025, and will complete requirements to be in-service by mid-2026. Costs are based on third-party estimates for similar work.

- Campbell B-K treatment wetlands design is complete, and part of a RAP that is currently being negotiated with the State. Costs for the treatment wetlands are based on third-party estimates for similar work. The ash harvesting and beneficiation project is part of the RAP currently being negotiated with the State. Costs for this project are based on bids from contractors.

- Campbell deep injection well: Due to the 2024 RCRA rules, the Steam Electric Effluent Guidelines ("SEEG"), and the anticipated closing of the Campbell plant, a long-term disposal method is required for the leachate from the dry ash landfill. Based on a feasibility study, a deep injection well is the selected alternative. Costs for this project are based on third-party estimates for similar work. This project is discussed later in this direct testimony.

- Cobb 0-8 ash removal was completed; however, EGLE has indicated that they will not accept the project as complete without removing the containment berms at the site. Costs for removing the berms are based on high level estimates from third parties for this work. The berms are projected to be removed and completed by August 2030, however, a 20" sanitary sewer line is located in a portion of the berm. The Company is negotiating with Muskegon County on the removal or moving of this line, which could impact/delay the project up to one to three years.

Q. Please explain the projected coal ash disposal costs.

A. As the Company explained in Case No. U-20849, the projected coal ash closure costs are a result of several changes that have occurred since the Company's previous depreciation case in Case No. U-17653. In April 2015, the Environmental Protection Agency ("EPA") published a final rule regulating coal combustion residuals ("CCRs"), such as coal ash, under RCRA. The final rule adopted minimum standards for coal ash landfills and surface impoundments including operational and closure standards, as well as standards for disposing of nonhazardous CCR materials and exempting management of materials that met requirements for beneficial use. Following the publication of the EPA rule, EGLE determined that more prescriptive state requirements should be established for coal ash facilities to align with federal requirements. In December 2018, EGLE enacted revisions

to its solid waste statute for coal ash units and submitted an application for a state permitting program to the EPA for approval.

Q. What is the status of EGLE's application for a state permitting program?

A. The EPA is reviewing the state's application now, but those requirements are already mandated under state statute. Compliance with those new requirements has caused the projected costs to increase. In May 2024, the EPA promulgated new rules regarding historic CCR materials which could impact future costs. Following the publication of those rules, the Company is still reviewing the impact to planned work and revising costs accordingly to comply with the rules. Where impacts are already known, the previous section has addressed in terms of project descriptions. Following the completion of facility evaluation reports due in February 2028, the Company will have further direction regarding impact to planned work and costs.

Q. Are there potential impacts of changing environmental regulations?

A. Yes. Consumers Energy continues to be subject to environmental regulations that will require the Company to make additional capital expenditures for historical ash closures, groundwater conditions, and effluent treatment, as well as ongoing capital expenditures for maintenance of previously installed equipment. The current and reasonably anticipated state and federal environmental statutes and regulations include but are not limited to: the SEEG, Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, the Michigan Mercury Rule, the Clean Water Act Section 316(b), and RCRA, as previously discussed. Consumers Energy anticipates continued costs associated with identified and evolving environmental compliance requirements that will need to be addressed in a timely manner.

Q. In your opinion, were these costs reasonably and prudently incurred?

A. Yes.

PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS, AND NEV

Q. Please describe Exhibit A-195 (MEW-1).

A. Exhibit A-195 (MEW-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending April 30, 2028, for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-196 (MEW-2).

Q. Please describe Exhibit A-196 (MEW-2), Generating Unit Availability Projections.

A. Exhibit A-196 (MEW-2) details Generating Unit Availability Projections for Consumers Energy's peaking generation, and hydraulic power generation for the projected test year beginning May 1, 2027, and ending April 30, 2028. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical NEV of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

Q. What factors cause an increase or decrease in ROR?

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates decreases ROR. Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

Q. How are ROR projections for the Generating units developed?

A. The ROR projections for the projected test year ending April 30, 2028, were developed from the five-year (2021-2025) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-196 (MEW-2), column (b).

Q. Please define PF.

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the management of emissions at gas generation facilities to stay within environmental limits.

Q. What strategy does the Company employ to minimize the impact of planned outages on its customers?

A. Consistent with the Company's generation asset strategy, the Company endeavors to schedule planned generating unit outages during periods in which the margin between the

generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater total NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand. However, with the introduction of seasonal capacity in the MISO market, the Company will also consider the impact of outage scheduling on capacity accreditation for the four capacity seasons. Company witness Hahn describes seasonal capacity in more detail in his testimony.

Q. Please define Projected Availability.

A. Projected Availability is a measure of the percent of time that a generating unit or category of generating units is projected to be available to generate electricity.

Q. How is Projected Availability determined for each generating unit or category of generating units?

A. The Projected Availability for each generating unit or category of generating unit is calculated as (100% - PF) * (100% – ROR). Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

Q. How does the Company's generation asset strategy inform Projected Availability?

A. As I previously discussed, the Company's generation asset strategy and associated generation investment will focus on each unit's ability to provide economic value to customers through the unit's ability to produce energy and capacity value in the respective MISO markets. As such, those generating units or category of generating unit providing the greatest amount of economic value to customers will be targeted to achieve the highest projected availabilities.

Q. How can the Company impact Projected Availability for a generating unit?

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

Q. Does the Company attempt to maximize availability for all its generating units or category of generating units?

A. No. Consistent with the Company's generation asset strategy, the Company focuses on sustaining availability for those generating units which provide the greatest economic benefit to customers through the energy value provided. The Company's generating units get dispatched by MISO as part of the MISO energy market. Based upon the Company's projected dispatch likelihood for each unit, the Company will rank the generating units from highest economic value to least economic value, and manage the PF and the ROR, and therefore the unit's availability, to allow for the highest customer value. Or, stated differently, the PF and ROR values may be allowed to be higher (lower unit availability) for the lower economic value units, and will be managed to lower values (higher unit availability) for higher economic value units.

Q. How does the availability projection reflect the customer benefit?

A. An improvement in availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis. Additionally, higher availability increases the ZRCs, increasing the capacity value of the unit.

Q. How does the Company measure the customer benefit resulting from increased generation?

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-196 (MEW-2), column (f), which identifies five-year (2021-2025) actual NEV amounts.

Q. What can the Company do to positively affect NEV?

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and

fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

Q. Does the cost of production vary for the Company's generating units?

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for its customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

Q. Why is the measurement of NEV important to the Company and its customers?

A. Positive NEV reflects a direct and immediate reduction to customer power supply costs and consideration of NEV provides a basis for making operational and financial decisions in order to maximize the customer value of the generating unit.

Q. What is another measure the Company uses to evaluate economic projects for its generating units?

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives monetary credit in the MISO Resource Adequacy Market. Table 3 below summarizes the current capacity value of the Company's generating units based upon the summer season results in the 2025-2026 PRA for Zone 7. Company witness Hahn discusses the capacity value of the Company's generating units in

the PRA in his testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 3

RESOURCE	MICHIGAN LOCATION	MISO ISAC[1] MW	MISO SUMMER SAC[2] MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[3]	CAPACITY VALUE ZONE 7 (75% CONE)[4]
OIL OR GAS FIRED					
Covert	Covert, MI	1089.5	952.9	$ 231,814,365	$ 70,178,191
DE Karn 3	Essexville, MI	602.1	367	$ 89,281,008	$ 27,028,435
DE Karn 4	Essexville, MI	586.8	542.3	$ 131,926,677	$ 39,938,748
Zeeland CC	Zeeland, MI	533.8	501.5	$ 122,001,159	$ 36,933,952
Zeeland 1A	Zeeland, MI	157.6	153.3	$ 37,293,674	$ 11,290,079
Zeeland 1B	Zeeland, MI	156.7	153	$ 37,220,693	$ 11,267,985
Jackson	Jackson, MI	531	508.6	$ 123,728,394	$ 37,456,845
HYDROELECTRIC					
Alcona	Alcona County, MI	2.7	2.7	$ 656,836	$ 198,847
Allegan	Allegan County, MI	1.2	1.2	$ 291,927	$ 88,376
Cooke	Iosco County, MI	7.2	6.8	$ 1,654,253	$ 500,799
Croton	Newaygo County, MI	2.1	2.1	$ 510,872	$ 154,659
Five Channels	Iosco County, MI	6.2	5.8	$ 1,410,981	$ 427,152
Foote	Iosco County, MI	2.7	2.8	$ 681,163	$ 206,211
Hardy	Newaygo County, MI	33.3	32.4	$ 7,882,029	$ 2,386,162
Hodenpyl	Wexford County, MI	4.1	4.1	$ 997,417	$ 301,953
Loud	Iosco County, MI	5	4.8	$ 1,167,708	$ 353,505
Mio	Oscoda County, MI	1.3	1.3	$ 316,254	$ 95,741
Rogers	Mecosta County, MI	2	2.1	$ 510,872	$ 154,659
Tippy	Manistee County, MI	5.8	5.8	$ 1,410,981	$ 427,152
Webber	Ionia County, MI	1	1	$ 243,273	$ 73,647
RENEWABLES					
Lake Winds	Mason County, MI	100.8	17.9	$ 4,354,578	$ 1,318,281
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	52.9	$ 12,869,115	$ 3,895,924
Crescent Wind	Jonesville, MI	166	24.4	$ 5,935,849	$ 1,796,986
Gratiot Farms Wind	Alma, MI	149.7	36.3	$ 8,830,792	$ 2,673,385
Heartland Farms Wind Park	Ithaca, MI	200	31.5	$ 7,663,084	$ 2,319,879
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	$ 413,563	$ 125,200
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	$ 145,964	$ 44,188
Cadillac Solar Garden	Cadillac, MI	0.5	0.2	$ 48,655	$ 14,729
Circuit West	Grand Rapids, MI	0.5	0.2	$ 48,655	$ 14,729
Muskegon Solar	Muskegon, MI	250	125	$ 30,409,063	$ 9,205,870
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1138.0 (owned share)	1110	$ 270,032,475	$ 81,748,128

1 ISAC = Intermediate seasonal accredited capacity
2 SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours
3 2025-2026 Summer PRA Settlement price of $666.50/MW-day for Zone 7.
4 2025-2026 PRA 75% CONE price of $269.03/MW-day for Zone 7.

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031, as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain capacity value from the

customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units, as well as maintain capacity accreditation. Critical reliability investments required to keep the units available will be included in the plan.

Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their projected performance?

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 16.83% at Karn Unit 3 and 17.83% at Karn Unit 4 in the test year, as shown on Exhibit A-196 (MEW-2), lines 1 and 2, column (c). During the five-year historical period from 2021 through 2025, Karn Unit 3 had an ROR of 32.28% and Karn Unit 4 had an ROR of 22.85%, as shown on Exhibit A-196 (MEW-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in the test year?

A. The projected availabilities for Karn Units 3 and 4 in the test year are 65.85% and 75.87%, respectively, as shown on Exhibit A-196 (MEW-2), lines 1 and 2, column (e). The availability for Karn Unit 3 reflects a projected ROR of 16.83% and a PF of 20.82%, as shown on Exhibit A-196 (MEW-2), line 1, columns (c) and (d). The planned outages for the test year are scheduled to begin on October 3, 2027, and last for 48 days, and April 3, 2028, and last for 28 days, as reflected on Exhibit A-195 (MEW-1), lines 2 and 3. The availability for Karn Unit 4 reflects a projected ROR of 17.83% and a PF of 7.67%, as

shown on Exhibit A-196 (MEW-2), line 2, columns (c) and (d). The planned outage for the test year is scheduled to begin on April 3, 2028, and last for 28 days, as reflected on Exhibit A-195 (MEW-1), line 4.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-196 (MEW-2), lines 1 and 2, column (f), during the five-year historical period from 2021 through 2025, Karn Unit 3 had an NEV of ($6.8 million) and Karn Unit 4 had an NEV of ($13 million). The 2025 NEV for each of these units was ($1.8 million) and ($3.4 million) for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 3, the capacity value based upon the settlement price for Zone 7 in the 2025-2026 PRA is $89.3 million for Karn Unit 3 and $131.93 million for Karn Unit 4.

The hypothetical capacity value based upon 75% of Cost of New Entry ("CONE") for Zone 7 in the 2025-2026 PRA is $27.0 million for Karn Unit 3 and $39.9 million for Karn Unit 4.

Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to increase economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets and the turbine projects discussed later in this direct testimony aim to increase customer value. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted at improving dispatch and reliability, such as the turbine projects, are included in the plan as they provide value to customers.

Q. How will the Company's generation asset strategy for the Zeeland Plant impact its projected performance?

A. Consistent with the benefits observed from the Phase I Gas Turbine Advanced Gas Path ("AGP") replacement and Axial Fuel Staging ("AFS") project, site performance is expected to further improve following the test year with implementation of the Phase II turbine replacement project, as discussed later in this direct testimony. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-196 (MEW-2), lines 10 through

12, column (c). During the five-year historical period from 2021 through 2025, the Zeeland Plant had ROR values at or below 5.27% for all units, as shown on Exhibit A-196 (MEW-2), lines 10 through 12, column (b).

Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in the test year?

A. The Projected Availability for the combined cycle generating units (Units 3, 4, and 5) at the Zeeland Plant in the test year is 88.64%, as shown on Exhibit A-196 (MEW-2), line 10, column (e). The Zeeland Combined Cycle Generating Unit availability is based upon a projected ROR of 4.0% and a PF of 7.67%, as shown on Exhibit A-196 (MEW-2), line 10, columns (c) and (d). The Projected Availabilities for each of the simple cycle generating units at the Zeeland site in the projected test year are 94.42%, as shown on Exhibit A-196 (MEW-2), lines 11 and 12, column (e). Each of the Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 1.64%, as shown on Exhibit A-196 (MEW-2), lines 11 and 12, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending April 30, 2028, however there are several shorter duration outages of 14 days, each scheduled in May and September 2027. There are no outages greater than 28 days scheduled for the Zeeland simple cycle units (Units 1 and 2) in the projected test year ending April 30, 2028, however there is a 7-day outage on each unit in the spring of 2028, a 3-day outage on each unit in September 2027. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to

maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Zeeland Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-196 (MEW-2), lines 10 through 12, column (f), during the five-year historical period from 2021 through 2025, the Zeeland Plant provided a total NEV of $327.5 million. The 2025 NEV for Zeeland was $85.9 million.

Q. Please quantify the capacity value for the Zeeland Plant.

A. As reflected in Table 3, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2025-2026 PRA is $196.5 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2025-2026 PRA is $59.5 million.

Q. Please provide an overview of the generation asset strategy for the Jackson Plant.

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040, consistent with the Company's Commission approved IRP, which evaluates long-term resource planning decisions. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Jackson Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 5.50% at the Jackson Plant in the test year, as shown on Exhibit A-196 (MEW-2), line 13, column (c). During the five-year historical period from 2021 through 2025, the Jackson Plant had an actual ROR of 7.73%, as shown on Exhibit A-196 (MEW-2), line 13, column (b).

Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in the test year?

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 93.28%, as shown on Exhibit A-196 (MEW-2), line 13, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 5.50% and a PF of 1.29%, as shown on Exhibit A-196 (MEW-2), line 13, columns (c) and (d). There is one major planned outage scheduled for 34 days beginning March 28, 2028, for the Jackson plant in the test year, as reflected on Exhibit A-195 (MEW-1), line 5.

Q. How does the Jackson Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-196 (MEW-2), line 13, column (f), during the five-year historical period from 2021 through 2025, the Jackson units provided a total NEV of $208.8 million. The 2025 NEV for the Jackson Plant was $43 million. This positive NEV reflects periods in which the Jackson plant was able to be dispatched over high-cost market purchases, positively impacting customer costs and reliability.

Q. Please quantify the capacity value for the Jackson Plant.

A. As reflected in Table 3, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2025-2026 PRA is $123.7 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2025-2026 PRA is $37.5 million.

Q. Please provide an overview of the generation asset strategy for the Covert Plant.

A. The strategic plan for the Covert Plant is predicated on plant operation through Planning Year 2040, consistent with the Company's Commission approved IRP. The overall long-term objective for the Covert Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted at improving reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Covert Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with past performance. Based upon the Covert Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 6.00% for all three units at the Covert Plant in the test year, as shown on Exhibit A-196 (MEW 2), lines 14 through 16, column (c).

Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the test year?

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 83.96% to 90.39%, as shown on Exhibit A-196 (MEW-2), lines 14 through 16, column (e). The Covert Unit 1 availability of 89.36% is based upon projected ROR of 6.00% and a PF of 4.93%, as shown on Exhibit A-196 (MEW-2), line 14, columns (c) and (d); the Covert Unit 2 availability of 83.96% is based upon projected ROR of 6.00% and a PF of 10.68%, as shown on Exhibit A-196 (MEW-2), line 15, columns (c) and (d); and the Covert Unit 3 availability of 90.39% is based upon projected ROR of 6.00% and a PF of 3.84%, as shown on Exhibit A-196 (MEW-2), line 16, columns (c) and (d). The Company will conduct inspections and balance of plant ("BOP") repairs at all three of the Covert Units during the test year, with nine-day outages in October of 2027 and April of 2028. The only planned outage for the test year that is 28 days or longer is for Covert Unit 2, which will include turbine inspections. This outage is scheduled for 30 days and planned to begin in February 2028, as reflected on Exhibit A-195 (MEW-1), line 1. The planned outages for the bridge period for Covert include an outage at Unit 1, which will begin in September 2026, and Covert Unit 3, that began in March 2026. These 59-day outages are for combustion turbine major inspections and BOP tasks. Covert Unit 1 and Unit 2 also began 29-day outages in April 2026 for Netmation upgrades. These outages are scheduled for periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Covert Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-196 (MEW-2), lines 14 through 16, column (f), during the 31-month historical period beginning June 1, 2023 through December 31, 2025, the Covert units provided a total NEV of $253.08 million. The 2025 NEV for the Covert Plant was $121.4 million.

Q. Please quantify the capacity value for the Covert Plant.

A. As reflected in Table 3, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2025-2026 PRA is $231.8 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2025-2026 PRA is $70.2 million.

Q. Please provide an overview of the Company's generation asset strategy for the River Hydro units.

A. The strategic plan for the Company's River Hydro units is currently predicated on the successful divestiture of the River Hydro fleet. On October 30, 2025, and October 31, 2025, the Company filed applications with the Federal Energy Regulatory Commission ("FERC") (Docket No. EC26-20-000) and the MPSC (Case No. U-21985) seeking approval for the FERC license transfer and sale of all 13 River Hydro facilities to Confluence Hydro, LLC. On February 18, 2026, FERC issued an order approving the Company's Section 203 Application, which ensures the transaction aligns with public interest and does not result in any negative impact to electric market competition or regulation. FERC is still in the process of administering the Company's request for the license transfer to Confluence Hydro. The application before the MPSC remains pending as of the filing of this case. In the interim, the Company will continue to operate the River Hydro units in accordance with its FERC project licenses. Continued operation of these

facilities is assumed in the Company's current IRP that was approved by the MPSC in Case No. U-21090. These units deliver customer value by providing renewable energy and capacity. River Hydro facilities also provide value to their surrounding local communities and to the state of Michigan in the form of recreational opportunities, natural preservation, and environmental benefits. The overall long-term objective for the River Hydro units is to maintain safe and reliable River Hydro sites for customers, to ensure compliance with FERC obligations and other regulatory requirements, and to continue providing valuable benefits to local residents, surrounding communities, and the state of Michigan.

Q. Has the Company presented any River Hydro capital investments in this electric rate case?

A. No. In the March 21, 2025 Final Order in the Company's 2024 Electric Rate Case No. U-21585, the Commission found that the "company may use deferred regulatory accounting of the revenue requirement on actual capitalized investments incurred subject to review in the company's next electric rate case."[2] The Commission went on to state that this accounting authority does not relieve the Company of meeting the evidentiary burden for its investments. As such, the Company has not presented any River Hydro projects for the bridge period and test year and intends to seek recovery in a future regulatory proceeding.

Q. Has the Company presented actual River Hydro investments for the historical test year?

A. No. As discussed in more detail in the direct testimony of Company witness Myers, the Company is requesting the continuation of the deferral through the test year of this rate

[2] Case No. U-21585, March 21, 2025 Final Order, page 157.

case and, as such, has not presented its actual 2025 River Hydro capital expenditures. This is due to the pending outcome of Case No. U-21985 and Docket No. EC26-20 for the sale of the River Hydros.

Q. How will the Company move forward if divestiture fails or is rejected by the Commission?

A. As stated by the Company in Case No. U-21985, should the Company be unable to obtain approval on acceptable terms for the sale of the River Hydros, the Company will do what is best for customers and proceed to decommission them.

Q. Is the Company requesting the recovery of O&M expense for the River Hydros in this proceeding?

A. Yes. The Company has reflected River Hydro O&M expense in Exhibit A-197 (MEW-4) for the historic year and the test year. The Company will discuss its proposal for future O&M expense later in this direct testimony.

Q. How will the Company's generation asset strategy for the River Hydro units impact their projected performance?

A. It is anticipated that future River Hydro unit performance will remain relatively consistent with current River Hydro unit performance, provided that necessary investments are made to ensure safe and reliable operation. In other words, as assumed in Consumers Energy's current IRP, the Company currently expects its River Hydro facilities can continue to deliver reliable clean energy to customers while maintaining their long record of operational, safety, and environmental performance. Based upon the River Hydro unit major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 5.03% for the River Hydro

units in the projected test year ending April 30, 2028, as shown on Exhibit A-196 (MEW-2), line 9, column (c). During the five-year historical period from 2021 through 2025, the River Hydro units had an ROR of 23.23% for all units, as shown on Exhibit A-196 (MEW-2), line 9, column (b).

Q. How is this strategy reflected in the Projected Availability for the River Hydro units in the projected test year?

A. The Projected Availability for all of the River Hydro units in the projected test year is 91.54%, as shown on Exhibit A-196 (MEW-2), line 9, column (e). The Projected Availability for the River Hydro units reflects a projected ROR of 5.03% and a PF of 3.61%, as shown on Exhibit A-196 (MEW-2), line 9, columns (c) and (d). These projections reflect 39-day outages at both Croton 1 and 2, as well as Rogers 3 and 4. The outages at Croton are planned to begin in October 2027 and the outages at Rogers are planned to begin in January 2028. There are also 82-day outages planned for Tippy 1, 2, and 3, scheduled to begin in July 2027. These outages are for electrical projects, maintenance inspections with electrical testing, and thrust bearing inspection.

Q. How does the River Hydro unit Projected Availability translate into customer value?

A. As reflected on Exhibit A-196 (MEW-2), line 9, column (f), during the five-year historical period from 2021 through 2025, the River Hydro units which are registered with MISO (Alcona, Croton, Hardy, Hodenpyl, and Tippy) provided a total NEV of $46.4 million. The 2025 NEV for the River Hydro units registered with MISO was $8.4 million.

Q. Please quantify the capacity value for the River Hydro units?

A. As reflected in Table 3, the capacity value of the River Hydro units based upon the settlement price for MISO Zone 7 in the 2025-2026 MISO PRA is $17.7 million and the

River Hydro unit hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2025-2026 PRA is $5.4 million.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 7.00% for the Ludington units in the test year, as shown on Exhibit A-196 (MEW-2), lines 3 through 8, column (c). During the five-year historical period from 2021 through 2025, the Ludington units had average ROR values ranging from 4.06% to 15.14%, as shown on Exhibit A-196 (MEW-2), lines 3 through 8, column (b).

Q. How do the Ludington Units factor into the Company's future renewable energy strategy as outlined in the IRP?

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio since it can deliver a significant amount of energy in a

short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy. However, defective and non-conforming work performed by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully provide these intended benefits over its remaining life.

Q. How is this strategy reflected in the Projected Availability for Ludington in the test year?

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 2.35% to 88.87%, as shown on Exhibit A-196 (MEW-2), lines 3 through 8, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 7.00% and PFs ranging from 4.44% to 97.48%, as shown on Exhibit A-196 (MEW-2), lines 3 through 8, columns (c) and (d). There are four major outages planned for the Ludington units in the test year: Ludington Units 1 and 2 each have a 43-day outage scheduled for September 2027, as reflected on Exhibit A-195 (MEW-1), lines 6 and 7. Ludington Unit 3 has a 120-day outage, with only 61 days landing within the test year, beginning on March 1, 2028, as reflected on Exhibit A-195 (MEW-1), line 8. This outage is to perform Distributed Control System ("DCS") Controls installation, Governor Controls upgrade, Intake Gate Controls replacement, Shaft Seal replacement, Corrective Work Scope, 3-yr inspections/Penstock Non-Destructive Examination ("NDE")/Parking Ledge & Discharge Ring condition inspection, and Oil Cooler Cleaning/Cooling Water Strainer Cleaning. Ludington Unit 4 has a 585-day outage, with 355 days landing within the test

year, beginning May 11, 2027, as reflected on Exhibit A-195 (MEW-1), line 9. This outage is to perform Discharge Ring Extension ("DRE") replacement, Wicket Gate and Headcover replacement, Main Shaft Seal replacement; 415 Motor Operated Disconnect ("MOD") replacement, Lower Generator Guide Bearing ("LGGB") Seal replacement, DCS Controls Installation, Governor Controls upgrade, nine-year inspections, turbine bearing replacements, Intake Gate Controls upgrade, Station Power Transformer ("SPT") replacements, and Generator inspection.

In addition, shorter outages on all six Ludington units are scheduled throughout the test year, primarily in the spring and fall. These outages will be used, in part, to perform cooling water strainer cleaning, install and remove the barrier net, and perform other necessary inspections. To the extent possible, the outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

Q. Please provide an overview of the generation asset strategy for the Renewable Energy Assets.

A. The Company's generation asset strategy for Renewable Energy Assets, including both wind and solar resources, is primarily driven by the Company's Commission-approved IRP and its approved 2024 REP. Consistent with those plans, the Company will continue to add renewable wind and solar resources through Commission-approved solicitations. The Company's 2024 REP Amendment, approved on September 11, 2025, provides for the addition of approximately 2,800 MW of renewable wind resources and 1,000 MW of renewable solar resources beyond the glidepath established in the Company's 2021 IRP settlement.

Q. Is the Company requesting recovery of renewable energy assets in this proceeding?

A. No. The Commission approved the movement of cost recovery for renewable energy resources to the Company's REP in its March 21, 2025 Order in Case No. U-21585. As such, all costs for renewable energy assets will be presented and reconciled in REPs.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-196 (MEW-2), lines 17 through 18, column (f), during the five-year historical period from 2021 through 2025, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of $179 million. As reflected on Exhibit A-196 (MEW-2), lines 19 through 20, column (f), during the four-year historical period from 2022 through 2025, Gratiot Farms Wind and Crescent Wind provided total NEV of $116.8 million. Heartland Farms Wind Park began commercial operation on December 29, 2023, and as reflected on Exhibit A-196 (MEW-2), line 21, column (f), generated $27.5 million in NEV in 2025. The Company began to measure the NEV for its solar assets in 2020 and the 2021 through 2025 NEV for its Solar Garden Assets totaled $1.6 million.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 3, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2025-2026 PRA is $70.7 million and the renewable asset hypothetical

capacity value based upon 75% of CONE for Zone 7 in the 2025-2026 PRA is $21.4 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Hahn provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the electric generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II

ENVIRONMENTAL REGULATIONS

OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

CURRENT (ON-GOING) ENVIRONMENTAL COMPLIANCE

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed with consideration for managing costs to customers consistent with regulatory and operational requirements. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company's existing AQCS complies?

A. Yes. In April 2022, the EPA proposed the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" under the "good neighbor" provision of the Clean Air Act ("CAA"). The EPA's rule was finalized, effective March 15, 2023, but this revision was stayed in 2024 and the prior 2017 Cross-State Air Pollution Rule ("CSAPR") remains in effect. On March 12, 2025, U.S.

EPA Administrator Lee Zeldin announced the agency will undertake action to "end the Good Neighbor Plan." It is most likely that CSAPR will remain in effect. The Company will continue to monitor the rule and evaluate various options for compliance as needed.

Q. What are the capital investments and/or O&M expenses the Company is seeking to recover in this case that are specifically related to air quality control?

A. Any O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibit A-197 (MEW-4).

Q. Are you seeking recovery of any expenses related to the regulation of greenhouse gases from EGUs?

A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings: (i) repeal of the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule and; (iii) issuance of new CAA section 111(d) regulations. In May 2024, EPA issued Final Greenhouse Gas ("GHG") standards for new and existing fossil fuel-fired EGUs under Section 111 of the CAA and the ACE Rule was repealed. Although Campbell has not yet permanently retired due to the DOE Order, the plant is still planned for retirement once those emergency orders conclude. Existing gas-fired combustion turbine units are not subject to this rule and therefore those Company units are also not subject to this rule. On March 12, 2025, EPA Administrator Lee Zeldin announced the agency will undertake actions "reconsidering regulations on power plants (Clean Power Plan 2.0)" which could imply that these regulations will be revised at some point in the future.

Environmental Regulations and Compliance Strategy – Waste

Q. Can you please describe the relevant parts of the RCRA as related to CCR management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed and signed into law. Section 2031 of the legislation provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has information

gathering and enforcement authorities to enforce the CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows EGLE to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Environmental Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

Q. What are the capital and/or O&M investments Consumers Energy is seeking to recover in this case that are specifically related to RCRA compliance and/or overall CCR Management?

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The Cost of Removal ("COR") and/or O&M required for the management of CCRs under the RCRA that the Company is seeking to recover can be found in Exhibit A-197 (MEW-4). The COR expenses represent historical expenses only. Separately, there are closure activities that will continue throughout the bridge period and test year and beyond; however, those expenses are COR and are not included in this filing.

Environmental Regulations and Compliance Strategy – Water

Q. Can you please describe the relevant parts of the SEEG as related to wastewater management?

A. On April 24, 2024, the EPA finalized a supplemental rulemaking to strengthen discharge limits for Flue Gas Desulfurization ("FGD") wastewater, bottom ash transport water, Combustion Residual Leachate ("CRL"), and legacy wastewaters. FGD and legacy wastewaters are not and will not be generated at Consumers Energy locations. As discussed earlier in this direct testimony, although Campbell was previously expected to retire in May 2025, the plant has remained operational pursuant to a series of continuing 90-day emergency orders issued by the DOE. Accordingly, while the Company awaits a determination regarding if and when Campbell will be permitted to retire, it will continue to operate the facility and comply with all applicable environmental requirements. In that regard, CRL discharge limits will impact the Campbell dry ash landfill, and the Company is completing a capital project to install a deep injection well to address these requirements. More detail regarding the status of the injection well project can be found later in my testimony. Paired with the 2024 RCRA rule, there is risk at the Weadock, Karn, Cobb, and Whiting sites. The 2024 RCRA rule requires the elimination of free liquid in closed ash landfills, but it only provides a broad definition of free liquid – it does not provide any performance basis or standard to determine if the requirement has been satisfied. If the 2024 RCRA rule were to require installation of dewatering wells in closed landfills, any wastewater generated would likely be classified as unmanaged CRL subject to arsenic and mercury limits and require treatment prior to surface water discharge.

Q. What are the capital and/or O&M investments Consumers Energy is seeking to recover in this case that are specifically related to RCRA compliance and/or overall wastewater management?

A. While the Company awaits clarity regarding if and when Campbell will be permitted to retire, it must continue to operate the facility and comply with all applicable environmental and wastewater regulations. In that regard, the Company is seeking to recover costs associated with the deep-injection well project at Campbell. Campbell has an active landfill that generates leachate requiring ongoing management, and the continued operation of the plant—together with decommissioning-related activities—requires the sitewide National Pollutant Discharge Elimination System ("NPDES") permit to remain in effect through demolition.

Consistent with SEEG and other applicable requirements, the Company evaluated multiple alternatives to address ongoing CRL management, including off-site disposal, off-site treatment, on-site treatment, and on-site disposal. Based on that evaluation, on-site disposal via a deep-injection well was selected as the most reasonable and cost-effective compliance option under the circumstances. By the time Campbell's retirement was delayed, the Company had already completed significant work associated with this selected compliance path, including alternative analysis, project selection, engineering, permitting activities with EGLE and the U.S. EPA and related regulatory filings.

Given the current stage of the project and the regulatory certainty it provided, the Company required a reasonable approach to pause this project. The Company determined that the most reasonable and prudent course of action was to advance the deep-injection well project to a defined and logical stopping point—specifically, completion of drilling—

while pausing the remaining elements of the project until Campbell is permitted to retire. This approach minimizes customer cost, preserves regulatory compliance, and avoids the inefficiencies associated with restarting or re-permitting the project at a later date.

As explained later in this direct testimony, this decision reflects a deliberate effort to balance near-term compliance obligations with long-term cost control, while maintaining flexibility in light of ongoing uncertainty surrounding the plant's retirement. The deep-injection well is currently being permitted by EGLE and the EPA. Projected capital expenditures associated with this project are reflected on page 8, line 33, and page 9, line 25 of Exhibit A-12 (MEW-3), Schedule B-5.2 for the bridge period and test year.

SECTION III

GENERATION CAPITAL EXPENDITURES

OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (MEW-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation for the historical year 2025 through the projected test year - 12 months ending April 30, 2028. Exhibit A-12 (MEW-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2025, the Projected 16-month Bridge Period beginning January 1, 2026, and ending April 30, 2027,

and the projected test year beginning May 1, 2027, and ending April 30, 2028. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit captures the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but are presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of the exhibit. Finally, pages 7 through 9 of the exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 6 of the exhibit. Specifically, page 7 of this exhibit presents capital projects for the Historical Period ended December 31, 2025; page 8 of this exhibit presents capital projects for the Projected 16-month Bridge Period beginning January 1, 2026, and ending April 30, 2027; and page 9 of this exhibit presents capital projects for the projected test year ending April 30, 2028.

Q. What project information is presented on Exhibit A-12 (MEW-3), Schedule B-5.2, pages 7 through 9?

A. Exhibit A-12 (MEW-3), Schedule B-5.2, pages 7 through 9, presents the generation type, the generation unit, project type, project classification, project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly; whereas non-routine projects are typically undertaken once every 10 years or longer. The budget approval reflects the status of internal approval for the project, including projected cost amount. Exhibit A-12 (MEW-3), Schedule B-5.2, page 7, includes both projected and actual capital project costs;

whereas, Exhibit A-12 (MEW-3), Schedule B-5.2, pages 8 and 9, includes only the project projected amount.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $220.702 million for the historical test year ended December 31, 2025 as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 1, line 17, column (b); $263.4million in the projected 16-month Bridge Period ending April 30, 2027 as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 1, line 17, column (e); and $163.0 million in the projected test year ending April 30, 2028 as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 1, line 17, column (f).

Q. Has the Company included any contingency in the requested capital expenditures for Generation?

A. No. The Company no longer includes contingency in its generation projects.

Q. Please explain how the Company prioritizes its capital investments within Generation.

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, compliance, and continued operation related projects. These projects are considered a mandatory cost of doing business. Safety, regulatory, compliance, and continued operation-related projects provide economic value to customers in that they allow the units to remain in service and avoid potential derates and/or shutdown due to an intervention by various regulators including Occupational Safety and Health Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact

of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis for the investments necessary to satisfy service quality, safety, and federal and state policy requirements.

Q. How does the Company determine whether other projects get approved for funding?

A. In accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce ROR, maintenance cost or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. In other words, the implementation of the project should, at a minimum, result in a marginal customer benefit.

Q. How does the Company evaluate other capital investments, such as economic projects?

A. The Company uses the Copperleaf Asset Investment Planning software tool as a means to evaluate and prioritize projected economic projects within Generation. The software utilizes financial models that allow the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units.

Q. Does the Company utilize the Copperleaf value to prioritize all projects?

A. No. The Company uses the Copperleaf value for economic projects that are not considered required but would yield net benefits to customers. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and results from a reasonable evaluation of alternatives. When evaluating project

alternatives related to regulatory, compliance, and/or continued operations, the Copperleaf models may be used to rank alternatives.

Q. Please explain what you mean by projects for continued operations.

A. Projects for continued operations refers to projects which are necessary to allow the generating unit to continue to operate through its retirement date. Alternatives for projects necessary for continued operation will generally be evaluated based upon LCBF. For this evaluation, one of the alternatives will include a decision to not perform the project and either retire the unit earlier than projected or operate the unit at a permanent derate.

Q. How does the Company evaluate customer benefits associated with generation-related capital investments?

A. The Company uses replacement power cost estimates and PSCR impacts when evaluating customer benefits. The Company also evaluates availability and heat rate improvements, which result in increased generation and/or lower cost generation.

Q. How does the Company evaluate historical events which have impacted availability?

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending April 30, 2028.

Q. Does the Company evaluate customer benefits associated with Outage Schedules?

A. Yes, the Company uses historical market prices to evaluate timing around outages in an effort to ensure the unit is available during periods in which market pricing is projected to be high.

Q. Is it possible that the Company could experience changes to its scheduled outages and forecasted capital expenditures in the future?

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2024. A review of the outage schedule used in this case identifies nine scheduled outages that begin in May 2027 (20 months after the schedule was approved) and run through April 30, 2028, 31 months later. During each of these nine scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

Q. Are there other reasons why outage schedule changes occur?

A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices. It is critical to point out that disallowance of projected capital expenditures in electric rate cases may lead to deferral or cancellation of

work scope and outage plans, thus pushing needed investment to the future, increasing operational and customer cost risk.

Q. Can you provide an example of when circumstances changed?

A. Yes. The Company's fall 2023 outages for Karn Units 3 and 4 were originally scheduled from October 1, 2023 through November 18, 2023. The Karn Unit 3 and 4 outages were not performed due to availability of materials for the major work that was planned. Due to the uncertainty of the retirement of Karn Units 3 and 4 as proposed in the Company's 2021 IRP, the preparation for these outages was not complete, including material delivery. As such the planned work was deferred to 2024.

Q. Please describe how the Company determines its generation projected capital expenditure amounts.

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant and reliable operations of the Company's electric generating fleet. Projected capital investments are informed by historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's electric generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

Q. How are projects identified that are discussed later in this direct testimony?

A. As of 2026, the Company has begun using an asset management and decision-making software called Copperleaf. Operations Engineering and Asset Health assess the equipment

performance and compare that assessment with the generation asset strategy for the generating unit. Upon identification of a potential project, the engineer will complete a GA-310 Funding Request in Copperleaf. Consistent with commonly used asset planning practices in the utility industry, this process defines the issue, alternatives considered for resolution, intended benefits or consequences avoided, and suggested timing and a cost estimate. The request is reviewed by multiple groups for alignment and ultimately routed for approval for inclusion in the Long-Term Financial Plan ("LTFP"). Funding requests entered into the LTFP will typically be scheduled three to five years in the future to align with outages and provide the project execution teams ample time to plan and engineer.

Q. How were the projected capital expenditure amounts developed for each of the projects discussed later in this direct testimony?

A. Each project begins with the creation of a Funding Request. The engineer will provide an initial cost estimate for the project within the Funding Request document. They utilize past experience, contractor cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and studies to provide the best estimate of the costs. This activity typically takes place three to five years prior to the start of project execution.

Q. How are Funding Requests related to Concept Approval Documents ("CADs")?

A. The Funding Request is the mechanism utilized to allow projects to be considered for the LTFP. Once the project is included in the LTFP and the project is within a year of start of execution, the CAD is created. The CAD is templated from the information included in the Funding Request and updated as necessary. The CAD is then routed for approval to the designated level of management based on project amount and, once approved, the project will be initiated.

Q. Do adjustments to the projected capital investment amounts for each of the projects occur prior to project implementation?

A. Yes. As the project team progresses through the life cycle of a project, there are multiple opportunities to better define project costs. Activities such as detailed engineering, bidding, contractor involvement, and construction all allow for budgets to be better defined. As this definition evolves, the projected capital investments are updated accordingly.

Q. How does the Company account for uncertainties in its cost projections?

A. When forecasting and budgeting for the Company's generation projects, the Company accounts for the uncertainty of less mature estimates by including contingency in its cost estimates. For purposes of this rate case filing, the Company has already removed the contingency component of its generation project cost estimates before filing the case since it has been disallowed in the past. The Company also utilizes industry standard cost estimating practices that involve class estimates having a prescribed range of potential cost outcomes based on estimate accuracy. The Commission has historically disallowed costs above the lower range for certain projects and cost estimate classes.

Q. What impact does this have on the Company's ability to fund needed generation capital projects?

A. With the company removing the contingency amount from the project prior to filing, and if the Commission disallows the amount consistent with the bottom end of the range of estimate accuracy, it is virtually certain to underfund the Company's generation capital projects.

2025 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2025 actual capital expenditure amount of $220.702 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21870?

A. In Case No. U-21870, the Company requested $193.846 million for the 12 months ending December 31, 2025. The 2025 actual capital expenditure amount of $220.702 million is $26.856 million more than the projected amount.

Q. What is the basis for the gap in projected versus actual spending?

A. The Company identified delays in the CODs for the BESS projects. The projected investment amount for the 12 months ending December 31, 2025, was $42.585 million and the actual capital expenditure amount was $65.883 million, a difference of $23.298 million.

The actual capital expenditures for Karn Units 3 and 4 for the 12-month period ended December 31, 2025, came in at $24.472 million, which is $15.272 million greater than the projected $9.2 million, primarily due to costs associated with an unplanned outage resulting from a fire at the Karn Unit 4 Generator Step-Up Transformer ("GSU") in February 2025, which also required repairs to shared equipment affecting Karn Unit 3.

Finally, the actual capital expenditures for Ludington for the 12-month period ended December 31, 2025, came in at $9.843 million versus the projected amount of $11.418 million. The total investment amount for Ludington was over $37 million, however a portion of the investment was recorded as a regulatory asset.[3]

[3] See the February 27, 2026, report in Case No. U-21310.

Q. How does the compilation of capital projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7, compare with the 16-month bridge capital projects reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8?

A. A comparison of the projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7, with the bridge period projects reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, reveals that there are 10 projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7, which were not reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8. In addition, there were 15 projects for the 16-month bridge period that were reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7.

Q. Please discuss the 16-month bridge period capital projects that were included on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7, due to the fact that their actual 2025 capital expenditure amount was less than $1 million, the project was disallowed, reduced in cost or removed, or not pursued in 2025. The disposition of the other capital projects which are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2 is provided below:

> Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company:

Project Description	Projected Amount (000)	Actual Amount
LCI Replacements (SFC)	$1,305	$0
Unit 2 - LTSA Capital - Extra work not included in contract	$194	$0
Unit 3 - LTSA Capital - Extra work not included in contract	$9,057	$0
Purchase of site spare GSU	$1,335	$0
LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement	$1,420	$0
LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	$42,429	$0
Phase II Turbine Replacements	$10,175	$0
Combustion Air Heater Replacement	$1,055	$0
Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$1,800	$0

Below is a discussion of the remaining million-dollar projects whose actual 2025 capital expenditures were less than projected:

- Covert Purchase of Site Spare GSU ($1,525,640). The projected 2025 spend for this project was $1,525,640. The actual spend in 2025 was $32,531 so the actual spend was significantly lower than projected in 2025. The reason for 2025 being lower is the lead time and milestone payments shifted out for the delivery of the GSU. The remaining planned spend is $4.546 million in the bridge period and $8.684 in the test year;

- Zeeland Purchase of Site Spare GSU ($2,257,037). During 2025, the Company spent a total of $66,995 on this project due to a milestone payment that shifted up into 2024. The reduction in 2025 spend was realized in Q4 2024. The remaining spend of $4.585 million is planned for the bridge period ending April 30, 2027, which will complete the project;

- Karn 4 ID Fan Inlet Damper Replacements ($3,008,256). The total spend for this project in 2025 was $407,663. The remaining $2.025 million in the bridge period will complete this project; the reason this project has pushed into the bridge year was some of the critical component lead times were longer than anticipated and would not be on site in time for the outage;

- Ludington Unit 1 Pony Motor Overhaul ($2,667,791). The total spend for this project in 2025 was $12,935. The remaining planned spend is $3.870 million in the bridge period and $3.270 million in the test year. The reason for the push of this spending out of 2025 was due to delays in engineering and material procurement. In addition, negotiations were ongoing with the third party and took longer than expected to ensure we got accurate numbers and terms and conditions were appropriate for the project;

- Ludington 480 Volt Motor Control Centers for Dike Load Center ("DLC") ($1,248,265). The Company spent $221,218 in 2025 versus the projected 2025 amount of $1,248,265. The remaining planned spend is $1.922 million in the bridge period and $1.558 million in the test year; and the underspend in 2025 was due to build delays from the supplier (Schneider); and

- Ludington Station Water Discharge Isolation Valve ($1,397,405). During 2025 the Company spent $844,005 of the projected amount of $1,397,405. The remaining planned spend is $639,000 in the bridge period. The reason this project was not executed in 2025 was the parts had longer lead times than anticipated resulting in the installation being pushed into Q2 2026.

Q. Please discuss the 2025 capital projects that were not included in Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 7.

A. Each of these capital projects is discussed below:

- Covert Main Steam ("MS") Tee Header Replacements (*2025 Actual:* $1,656,469). The basis of this project is discussed in more detail later in this direct testimony;

- Jackson LM1-6 Variable Inlet Guide Vane ("VIGV") (*2025 Actual*: $1,506,620). The basis of this project is discussed in more detail later in this direct testimony;

- Karn Units 3 and 4 Boiler Plant Heating (*2025 Actual*: $1,193,267). Karn units 3 and 4 require steam daily for multiple auxiliary systems. The steam provides plant heating in the colder months, boiler freeze protection, and oil viscosity year-round. Karn Units 1 and 2 used to provide this steam. With the closure of Karn Units 1 and 2 in June 2023, Karn Units 3 and 4 needed a means of providing ≈3000 to 5000 lbs./hr. steam in the warm months up to 50,000 lbs./hr. in the colder months. The current auxiliary boilers (Vintage 1975/1977) provide 225,000 lbs./hr. steam which is adequate for unit startup but far surpasses the daily non-operational needs with no capability to turn down the output. Past practice for short durations when Karn Units 1 and 2 were unavailable, has been to vent excess steam generated by auxiliary boilers. This is both highly inefficient to perform year-round and would also cause accelerated damage to the vent piping, boiler tubing, and burners. Time to failure cannot be predicted and could be catastrophic in nature. This project was to install two smaller skid-mounted gas fired units with associated auxiliary equipment and piping, to provide sufficient steam required annually at necessary flow rates. A smaller rental (leased) unit was installed to facilitate steam requirements at plant separation, with the option for permanent purchase within the year;

- Karn Unit 4 Transformer Fire Capital (*2025 Actual*: $2,304,380). The basis of this project is discussed in more detail later in this direct testimony;

- Zeeland General Electric ("GE") Long-Term Service Agreement ("LTSA") Payments Unit 1A (*2025 Actual*: $14,730,863). For Zeeland Unit 1A, the Company incurs several categories of costs under the Unit 1A LTSA that ensure continued safe, reliable, and efficient operation of the combustion turbine. These LTSA-related expenditures include: Quarterly ("QTR") Fees, which represent the standard monthly LTSA service charges assessed on a quarterly billing cycle and are required to maintain OEM support and technical coverage; Milestone Payments, which fund OEM-supported component upgrades and performance-enhancing modifications executed during major maintenance

intervals; MISO Fees, which support Unit 1A's ongoing participation in the MISO energy and capacity markets; and Generator Interconnection Agreement ("GIA") Application Fees, which are administrative and compliance-related charges associated with maintaining Unit 1A's interconnection obligations. Collectively, these costs support Unit 1A's operational reliability, regulatory compliance, and long-term performance. Consistent with the Company's generation asset strategy, these expenditures ensure that Unit 1A continues to provide high-value energy and capacity benefits to customers and remains positioned to meet future system needs efficiently and cost-effectively;

- Zeeland GE LTSA Payments Unit 1B (*2025 Actual*: $14,747,637). For Zeeland Unit 1B, the Company incurs several categories of costs under the Unit 1B LTSA that ensure continued safe, reliable, and efficient operation of the combustion turbine. These LTSA-related expenditures include: Quarterly ("QTR") Fees, which represent the standard monthly LTSA service charges assessed on a quarterly billing cycle and are required to maintain OEM support and technical coverage; Milestone Payments, which fund OEM-supported component upgrades and performance-enhancing modifications executed during major maintenance intervals; MISO Fees, which support Unit 1B's ongoing participation in the MISO energy and capacity markets; and Generator Interconnection Agreement ("GIA") Application Fees, which are administrative and compliance-related charges associated with maintaining Unit 1B's interconnection obligations. Collectively, these costs support Unit 1B's operational reliability, regulatory compliance, and long-term performance. Consistent with the Company's generation asset strategy, these expenditures ensure that Unit 1B continues to provide high-value energy and capacity benefits to customers and remains positioned to meet future system needs efficiently and cost-effectively;

- Zeeland GE LTSA Payments Combine Cycle (*2025 Actual*: $11,748,160). For the Zeeland Combined Cycle LTSA, the Company incurs several categories of charges associated with maintaining and upgrading the Phase 2 combustion turbine units. These charges include: QTR Fees, which represent the regular monthly service fees assessed under the LTSA and billed on a quarterly basis. Milestone Payments, which fund OEM-supported upgrades and performance enhancements executed during major inspection intervals. MISO Fees, which support required market participation services for the units; and GIA Application Fees, which reflect administrative and compliance-related costs associated with the units' interconnection obligations. These costs collectively support ongoing reliability, regulatory compliance, and performance optimization for the Zeeland Phase 2 combined-cycle assets, and are consistent with the Company's generation asset strategy to maintain high-value natural gas units that provide significant reliability and customer benefit;

- Ludington LPS Units 2 and 4 Head Cover & Bottom Ring Replacement (*2025 Actual*: $ 3,090,887). The basis of this project is discussed in more detail later in this direct testimony; and

- Generation – IT/Cyber Security Capital (*2025 Actual*: $1,718,744). The next step in Commercial Operations Digital transformation is to implement the Power Costs Incorporated ("PCI") Insights module. The PCI Insights module is a Software as a Solution ("SaaS") that allows accessibility to an organized catalog of Consumers Energy's market data for easy import/export capabilities and connection to apps, Application Programming Interfaces ("API"), and PowerBI tools. The software architecture processes very large data sets in minutes and allows the ability to leverage out-of-the-box reports as well as customizable report options. Part of this project is also to upgrade the Contract Settlements ("CS") module to make it compatible with Insights, which will provide data accessibility the Company never had before for PPAs. Additional CS upgrade functionality includes cleanup of dashboards, standard contracts and automatic imports, approval process automation, replacement of Adobe PDF billing process. Finally, the CS upgrade eliminates the need for multiple standalone databases related to PPAs and integrate all the data within PCI with Insights reporting capabilities.

The following project was to support the separation of Karn Units 1 and 2 from Karn Units 3 and 4. This unit separation work was presented in the Company's 2021 IRP, the Company's 2023 Electric Rate Case No. U-21389 but was not appropriately reflected in the Company's 2024 Electric Rate Case No. U-21585 as it was erroneously reflected as decommissioning/COR. This project was required to operate Karn Units 3 and 4 independent of Karn Units 1 and 2 following their retirement on May 31, 2023.

- Karn Units 3 and 4 Separation Assets (*2025 Actual*: $ 14,214,802). The Company undertook a series of projects to fully separate Karn Units 3 and 4 from the retired Karn Units 1 and 2. Because the original site configuration relied on shared electrical, water, steam, and fire-protection systems, the retirement of Units 1 and 2 necessitated installation of standalone systems to ensure the continued safe and compliant operation of Units 3 and 4. The Company executed multiple separation activities, including auxiliary boiler bypass piping, DCS modifications, installation of a demineralized water trailer and Pulse Jet Fabric Filter ("PJFF")/high pressure ("HP") house service separation. The Company completed major separation work such as 138-kV electrical utility separation, "cold and dark" isolation of the former Units 1 and 2 infrastructures, installation of a new fire water system and fire water building addition, construction of an aboveground storage tank, and rerouting of critical sump discharge piping. These activities were required to maintain regulatory compliance, preserve fire-protection capability, and ensure operator safety. They also enabled Units 3 and 4 to continue operating independently through their planned retirement dates, avoiding derates, operational constraints, and reliability risks that would otherwise arise from reliance on systems no longer

supported after the retirement of Units 1 and 2. These expenditures were essential to maintain safe, reliable, and environmentally compliant operation of Karn Units 3 and 4.

PROJECTED 16-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES

Q. How does the projected 16-month bridge period capital expenditure of $263.4million compare to the amount of capital requested by the Company in Case No. U-21870 for 2026?

A. The 16-month bridge period projected capital expenditure amount of $263.4 million compares similarly with the $248.262 million for the 16-month period beginning January 1, 2026, through February 28, 2027. A compilation of the 16-month bridge period projects which have projected capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, and an explanation of the project changes is described in more detail later in this direct testimony.

Q. How does the compilation of 16-month bridge period capital projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9?

A. A comparison of the 16-month bridge period capital projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, reveals that there are 15 projects on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9. In addition, there were three projects for the 12-month period ending April 30, 2027, that were reflected on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (MEW-3),

Schedule B-5.2, page 8. The River Hydro projects were not considered in this evaluation due to their removal.

Q. Please discuss the test year capital projects that were included on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than $1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Jackson	Engine 191-306 Overhaul	Project reduced to under $1 million
Zeeland	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	Project completed prior to bridge period
Karn 4	Combustion Air Heater Replacement	Project reduced to under $1 million

Q. Please identify the 16-month bridge period capital projects that were not included on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8.

A. The bridge period capital projects that were not included on Case No. U-21870, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, are presented in the table below:

Line No.	Site	Project Description
1	Covert	Air Compressors
2	Covert	U1-3 Circ water pumps replacements
3	Covert	DCS Evergreen Replacement
4	Covert	Main Steam Tee Header Replacements
5	Covert	U 1,2,3 NERC Relay Replacements
6	Jackson	GE LTSA Historical Owner Obligations Cap Portion
7	Jackson	LM1-6 VIGV-variable inlet guide vane
8	Zeeland	PH 1 & PH 2 High Recovery Gas Valves
9	Karn 4	Karn 4 Transformer Fire Capital
10	Ludington	U2&U4 Head Cover & Bottom Ring Repl
11	Ludington	Station Power Trnsfrmr Life Cyc Mgmt
12	Ludington	LPS Admin Building
13	Battery Storage	Incremental 300MW Battery Energy Storage System

The basis for these projects will be discussed in more detail later in this direct testimony.

Q. Is the projected capital expenditure amount of $263.4 million for the 16-month bridge period ending April 30, 2027, on Exhibit A-12 (MEW-3), Schedule B-5.2, page 1, column (e), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (MEW-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (h), $34.408 million will fund BESS projects, $187.303 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $12.093 million will fund projects listed as Administrative and Other, and $29.603 million will fund various projects at the LPS facility. With the exception of the BESS projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The BESS projects will be discussed in the direct testimony of Company witness Clark.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $163.084 million for the test year ending April 30, 2028, on Exhibit A-12 (MEW-3), Schedule B-5.2, page 1, column (f), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (MEW-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (j), $128.292million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $5.240million will fund projects listed as Administrative and Other,

and $29.552 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019. Except for the BESS projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The BESS projects will be discussed in the direct testimony of Company witness Clark.

Covert Plant

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2027, and projected test year ending April 30, 2028, for Covert.

A. At the Covert Plant, the Company plans to invest a total of $88.711 million in the 16-month bridge period and $47.252 million in the test year, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 2, line 43, columns (h) and (j), respectively. These capital investments will be facilitated by nine-day outages at Covert Units 1 through 3 in the Spring and Fall of 2026 and 2027, as well as Spring 2028. Additional longer unit outages for major inspections, including a 59-day outage at Covert Unit 3 that began in March 2026, and a 59-day outage at Covert Unit 1 that is scheduled to begin in September 2026. Covert Units 1 and 2 are each scheduled for a 29-day outage in Spring 2026 for Netmation upgrades. Covert Unit 2 is also scheduled for a 30-day outage in February 2028 for turbine inspections, BOP repairs, and water wash.

Q. What is the basis for the projected $88.711 million capital investment in the 16-month projected bridge period and $47.252 million in the projected test year?

A. The projected $88.711 million capital investment in the projected bridge period and $47.252 million in the projected test year will fund numerous projects at the Covert Plant. Ten projects in the bridge period, and six projects in the test year, are greater than $1 million. These projects are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, lines 1 through 10 and page 9, lines 1 through 6, respectively. The basis for these projects is described below:

- Load Commutated Inverter Static Frequency Converter ("SFC") Replacements (*Bridge Period*: $3,021,220 – *Test Year*: $1,748,918). The scope of this project is to replace the two SFCs which are both original to the plant's construction in 2001. The replacement of the SFC controls is required to mitigate the significant risk of failure due to obsolescence, ensure operational reliability, and align with manufacturer recommendations. The Covert Generating Station SFC Controls Replacement project is essential to address significant operational and reliability issues stemming from the obsolescence of the current SFC controls. The CAD for this project is attached as Exhibit A-199 (MEW-6);

- Purchase of site spare GSU (*Bridge Period*: $4,545,744 – *Test Year*: $8,684,257). Covert Generating Station consists of three gas turbine powered plants and three steam turbine powered plants placed in a one-on-one combined cycle configuration. The units transmit their power to the grid via GSUs. Each gas turbine powered unit feeds the secondary winding of a three-winding transformer, while the associated steam powered unit feeds the tertiary winding of the transformer. The GSU is rated for 500 MVA with forced oil and forced air. If a GSU were to fail, then the associated turbines would not be able to transmit power and would not be able to generate market value for Consumers Energy and its customers. The lead time for a GSU is currently three-to-four years and spare units at other facilities typically do not exist, especially for this more unique design application. The oil analysis of Covert transformers revealed the presence of chemicals for corrosive sulfur. Mitigating actions are being taken, however, this failure mode puts these transformers at increased risk of failure. The CAD for this project is attached as Exhibit A-200 (MEW-7);

- Netmation (Operating System) – Units 1 through 3 (*Bridge Period*: $7,646,667 – *Test Year*: $693,333). 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. The scope of this project is an extensive

upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, input/output ("I/O") modules, servers, workstations, network switches, and software to the latest architecture. The CAD for this project is attached as Exhibit A-201 (MEW-8);

- Covert Units 1 through 3 Emerson Digital Control System ("DCS") Evergreen (*Bridge Period*: $1,451,700). The scope of this project is to upgrade the DCS to the latest version to enhance security, gain compliance with enterprise standards, and achieve technological advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation 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. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the version 3.5.1. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing the end of support and requires updating to allow support of the latest Ovation versions. The BOP control is achieved with the Ovation DCS. Its architecture is comprised of controller and operator "drops" (processors and PCs) that provide the control of the equipment with I/O modules. Some of these I/O modules are in the same electrical cabinets that contain the "controller drops" (processors). Other I/O is in "remote" electrical cabinets, away from the "controller drops." The existing plant control is comprised of many remote I/O cabinets throughout the site. The communication modules to these cabinets have experienced failures in the past that can trip the generating units offline. Power supplies in the Ovation cabinets have reached the end of their recommended life and need to be replaced. The architecture and components need to be upgraded and replaced with the latest

Ovation design. The CAD for this project is attached as Exhibit A-202 (MEW-9);

- Covert Plant LTSA (*Bridge Period*: $26,813,279 – *Test Year*: $23,093,820). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an Effective Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. During the bridge period and test year, the Company will be conducting major inspections on all three generating units. A confidential copy of this agreement has been attached as Exhibit A-203 (MEW-10)-CONF;

- Covert Unit 1 LTSA Owner Obligations (*Bridge Period*: $9,023,670 – *Test Year*: $3,390,000). The LTSA owner obligations is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, and (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include, but are not limited to: (i) Steam turbine rotor

repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection for Covert Unit 1 begins on September 1, 2026 and ends on October 30, 2026. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as closely as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units. A confidential copy of this agreement has been attached as Exhibit A-203 (MEW-10)-CONF;

- Covert Unit 3 LTSA Owner Obligations (*Bridge Period*: $11,513,408 – *Test Year*: $180,000). The LTSA owner obligations is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, and (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include but are not limited to: (i) Steam turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection on Covert Unit 3 begins on March 15, 2026,

and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and high pressure ("HP") stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope of work. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as closely as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units. A confidential copy of this agreement has been attached as Exhibit A-203 (MEW-10)-CONF;

- Covert Units 1 through 3 NERC Relay Replacements (*Bridge Period*: $1,514,040 – *Test Year*: $415,233). This project is needed to preclude unnecessary risk associated with possible relay failures as the existing relays are at the end of life. Running to failure is not an option for relay protection equipment because of the extremely high costs of equipment failures that could result if relay protection schemes failed to operate as designed. In late 2024, Covert experienced its first indication of a relay failure on Unit 3 and is operating at this time with no redundant protection in this specific zone. The failed relay is original to the plant and with additional relays being of the same vintage, there is risk for more age-related failures.

  A failure of the remaining protection scheme in this zone would result in a forced outage, and it is expected that the turn-around time for sourcing, testing, installation, and commissioning of relays like this would take approximately two weeks if all went well. Relay manufacturers and Consumers Energy's High Voltage ("HV") Distribution group use 25 years as recommended service life for these types of devices. Each unit has multiple digital protection relays to ensure protection to the generation equipment (Generators/Exciters/Transformers) from local faults as well as to ensure protection from grid disturbances that could damage our valuable equipment. The original relays at Covert were not installed with the necessary test and cutout switches, which requires that the unit be offline for maintenance and replacement and creates greater potential for human performance errors that can jeopardize system reliability. The CAD for this project is attached as Exhibit A-204 (MEW-11);

- Covert Units 1 through 3 Circulating Water Pump Replacements (*Bridge Period*: $1,581,000 – *Test Year*: $2,035,012). The Circulating Water Pump Replacement project is a critical initiative aimed at replacing the Unit 3A circulating water pump and motor, which have been in operation for over 20

years and have reached the end of their service life based on failure data compiled from the rest of the circulating water pumps on site. This replacement is necessary to maintain plant reliability and avoid potential unit derates. The CAD for this project is attached as Exhibit A-205 (MEW-12);

- MS Tee Header Replacements Units 1 and 3 (*Bridge Period*: $5,455,051 – *Test Year*: $227,294). The Company needs to replace the following steam line components based on findings and replacements that occurred during the 2025 Covert Unit 2 outage: for both units, MS 12"x12" Bypass Tee (B16.9), Hot Reheat 20"x20" Bypass Tee (B16.9), and 12" MS line assembly from the Heat Recovery Steam Generator ("HRSG") outlet manifold to the HRSG manual isolation valve. These planned replacements will both reduce the safety risk of a MS line failure at the site and minimize unit outage time. This will be accomplished by pre-fabricating and planning for the scope of work in advance of the respective outages. In 2025, significant findings were identified in Unit 2's high-energy piping system ("HEPS") that triggered immediate replacement of localized sections. These findings consisted both of a recognized industry problem of crack formation in the 'junction' of the B16.9 tees along with significant weld defect which is attributable to the transient stresses imposed during unit trips causing over-stressing of the lines. Linear Phased Array inspections of the girth welds identified areas in which crack propagation reached or exceeded half wall indication and to which attempted localized repairs only resulted in more crack formation in the adjacent base metal. The CAD for this project is attached as Exhibit A-206 (MEW-13); and

- Plant Replace Sulfuric Sodium Hypo and Building (*Bridge Period*: $709,339 - *Test Year*: $1,233,633). The project involves replacing the existing sulfuric acid and sodium hypochlorite dosing systems and the building housing these systems at Covert. The current sodium hypochlorite system, in operation since 2004, has experienced over 60 documented failures, leading to chemical releases and hazardous cleanup situations. The system has surpassed its expected life cycle, posing increased risks of employee exposure, injury, and environmental contamination. The primary objective is to replace the aging sodium hypochlorite and sulfuric acid dosing systems and their housing structure to mitigate the risks associated with chemical spills and exposure to hazardous vapors. By separating the dosing systems, the potential for a combined spill creating chlorine gas is significantly reduced. The CAD for this project is attached as Exhibit A-207 (MEW-14).

The following projects are less than $1 million, but are important to reliability:

- Covert Unit 2 LTSA Owner Obligations (*Bridge Period*: $240,000 – *Test Year*: $360,000). The LTSA owner obligations is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor

and material to replace the following: blading, ammonia delivery system, Selective Catalytic Reduction ("SCR") catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The Company's LTSA with MEPPI does not cover this scope of work;

- Air Compressors (*Bridge Period*: $360,000). The plant commons instrument air supply system has been in service since the commissioning of the Covert gas generation station. The system provides all the air supply needed for equipment reading instruments and for all the pneumatic valves on site. This air system is crucial to the reliable operation of the plant. With the in-service equipment, many components are becoming obsolete, making them difficult to service, or impossible to service. With long lead times, this will result in a derate or risk the unit being taken off-line until a comparable part can be obtained and the air system can be repaired. The current system has three compressors in service, which are all needed to meet the needs of the site, as there is no redundancy if the site loses one. The anticipated outcome is to replace the current system with an updated, two compressor system, that would supply the plant with an adequate air supply using one compressor. The new system would implement redundancy in the system and eliminate the risk of a plant derate or unit shutdown;

- Covert Unit 2 Ammonia Dilution System (*Bridge Period*: $828,000). The existing ammonia dilution fan systems are critical to environmental compliance but have demonstrated persistent reliability issues due to their exposure to hot exhaust gases and mechanically complex design. These conditions make fan and motor alignment difficult, drive frequent failures, and require repeated annual rebuilds. Because the systems cannot be isolated for online maintenance, failures have previously resulted in full unit shutdowns, creating operational risk and potential environmental compliance concerns. The recommended solution is replacement of the existing fan-based configuration with an Ammonia Vaporization Optimization System ("AVOS"), which uses turbine exhaust gas thermal energy to efficiently vaporize ammonia through a gas-to-gas heat exchanger. This design eliminates electric heaters and large dilution air fans, significantly simplifying the system while removing known reliability weak points. The replacement improves reliability, reduces maintenance burden and parasitic losses, enhances ammonia vaporization consistency, and supports improved SCR performance and environmental compliance, making it a prudent and necessary investment for long-term unit operability;

- Covert Units 1 through 3 Replace Attemperators (*Bridge Period*: $840,000 – *Test Year*: $630,000). The attemperator is used to control the temperature of superheated steam. It injects a controlled amount of water into the steam flow, which reduces the temperature of steam to the desired level. The purpose of this project is to replace the existing single-spray nozzle attemperator with a multi-spray head attemperator. A multi-nozzle spray attemperator offers greater flexibility and rangeability, allowing for more precise temperature

control and better performance, especially in applications with varying steam flow and cooling water needs. The benefit of switching to a multi-spray nozzle attemperator is to offer better temperature distribution and higher heat flux compared to a single-nozzle system. Multi-spray nozzle attemperators offer more control availability that can be opened or closed individually, or in combination, to vary the cooling water flow. This allows a multi-head attemperator to achieve higher turndown ratios (the range of flow a device can handle) compared to single-nozzle units;

- Covert Unit Cooling Tower Gearboxes (*Bridge Period*: $900,000 – *Test Year*: $675,000). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines;

- Linear Variable Differential Transformers ("LVDT") Positioning Sensor – Units 1 and 3 Fuel Control Valves (*Bridge Period*: $760,500 per unit). The scope of these projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement will include the following devices: Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism. The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Gas Turbine Generator ("GTG") and Steam Turbine Generator ("STG") Auto Voltage Regulator – Covert Units 1 and 3 (*Bridge Period*: $900,000 each). The current MEC5000 digital automatic voltage regulators ("D-AVR"), which are over 20 years old, pose a substantial risk of failure. Any failure in these

D-AVRs renders both the GTG and STG on the affected unit unavailable, leading to extended outages and significant financial impacts. The OEM has indicated a lead time of 18-24 months for new D-AVRs and AVR parts, further exacerbating the potential downtime. The Covert Generating Station, operational since 2004, faces significant challenges with its aging MEC5000 D-AVRs. These regulators, critical for controlling the generators' response to load demand, are obsolete and no longer supported by the OEM, Mitsubishi Electric. This project proposes the replacement of the MEC5000 D-AVRs with the advanced MEC700 AVR System for Units 1 and 3, to mitigate obsolescence risks and ensure reliable operation;

- BOP Valves – Covert Unit 1 (*Bridge Period:* $675,000). The scope of this project is the replacement or overhaul of the BOP valves. Project is to overhaul the U1 HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt in 2017 and PV110 has never been overhauled. These valves are used for startup, shutdown and unit trips to bypass steam to the condenser and experience extreme service conditions that should be considered for overhaul every 7 to 10 years. These projects should align with major outages to allow for ample time to disassemble, inspect and repair. Overhauling the valves results in reliable dependable service as these valves are critical to starting up and shutting down the unit. They must also operate during trip conditions to prevent an overpressure event and potential damage to other components;

- BOP Valves – Covert Unit 3 (*Bridge Period*: $675,000). The Scope of this project is to overhaul the HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt in spring 2019 and PV110 has never been overhauled. These valves are used for startup, shutdown, and unit trips to bypass steam to the condenser and experience extreme service conditions that should be considered for overhaul every 7 to 10 years;

- Gas Compressor Controls Replacement (Programmable Logic Controller ("PLC") replacement) (*Bridge Period:* $720,000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface ("HMI") (Panel View 1000) and Allen Bradley PLC5Programmable Logic Controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;

- HRSG Expansion joint replacement (*Bridge Period*: $540,000). The scope of this project is to replace the vertical round expansion joint between the combustion turbine and the building and the HRSG. The Covert Generating Station HRSG expansion joint replacement project addresses the critical issue of aging expansion joints on all three units. These joints have a design life of 6 to 8 years and are typically replaced during turbine major outages. However, the existing expansion joints will be at least four years beyond their design life if replacement is delayed until the next major outage. This significantly

increases the probability of failure, which could start as a small tear detectable by thermography but could also result in a large rip. Such failures would allow exhaust gases to bypass the stack and environmental monitoring equipment, releasing high-temperature gas inside the building, posing a personnel hazard and significantly impacting overall heat rate efficiency. A failure of the expansion joint could force the unit offline for 30 days until it is replaced, potentially resulting in a month of downtime if the failure is severe;

- Covert Units 1 through 3 MTX HV Bushing – GSU (*Bridge Period:* $634,500 per unit). The 1MTX GSU transformer has over 20 years of service life and its HV bushings are showing insulation deterioration that was exposed through power factor testing prior to Consumers Energy ownership. The GSU also is overdue for internal inspection with attention to mitigate risk for its pacified oil that is still exhibiting corrosive potential properties. To engineering's knowledge this unit has never been fully drained and undergone internal inspection prior to or after the oil pacification work was performed earlier in its life. The unit has oil that was pacified for corrosive sulfur, however Doble and other industry experts strongly recommend the pacified oil be replaced as soon as possible since sulfur corrosion leading to failure is still probable due to remaining residuals in the pacified oil. It was noted in the root cause analysis for the Zeeland Unit 2C GSU that corrosive sulfur had an impact on its failure by reacting with conductors to create localized overheating. The HV bushing replacement mitigates any potential for failure in service. The bushing insulation properties continue to degrade over time as indicated through recent power factor testing before Consumers Energy took over the site. HV bushings power factor test results give the impression the bushings of 1MTX should have 5 to 10 years of life remaining before failure is realized, however neither the rate of deterioration nor exact failure timeframe is predictable. Due to lead times, planning for replacement is a more cost-effective solution for customers than verifying they are failing during a future outage and forcing extension until they can be replaced. A major outage for Covert will be required to have enough time to execute the work, which will require at least 12 days based on similar scope at ZGS. Internal inspection is part of the preventative maintenance plan and helps the Company determine the health of the transformer, plan future outages as needed, and prevent forced outages, thereby reducing potential ROR;

- Covert Warehouse addition with Loading Dock *(Bridge Period:* $15,000 - *Test Year*: $450,000*).* The warehouse will require extra storage space and an unloading crane that can handle receiving and storage of large components, such as circulating water pumps, large motors and fans. Covert needs more storage space to accommodate planning large projects and being able to store and keep critical components dry. Covert does not have these capabilities with the current configuration. This addition will resolve the semi-truck logistics and encompassing extra permanent office spaces that are needed for the added permanent plant personnel and the personnel that support Covert outages;

- Surge Protecting ("SP") Spare Transformer (*Bridge Period*: $25,000 - *Test Year:* $641,487). Covert site has three generating units, each having their own Auxiliary Transformer that supplies power to equipment necessary for generating including HRSG feed pumps, chillers, static starters and cooling towers. These Auxiliary Transformers had oil tested by Doble in 2010 and determined to have unacceptable levels of corrosive sulfur. Consumers Energy experienced failures of power transformers at Zeeland Generating Station with corrosive sulfur. These transformers are due for maintenance testing, to be repeated every 5 to 7 years concurrent with outages. Considering the lead time for power transformers is approaching three years, it is prudent to have a spare transformer on hand, especially since there is elevated risk of failure for the existence of corrosive sulfur. In the event the corrosive sulfur causes an emergent failure, or the testing reveals failure is near, the spare can be swapped out on a planned basis;

- Hydrogen New Bulk System (*Bridge Period*: $217,500 - *Test Year:* $390,000). Covert generating Station is a three unit combined cycle power plant. Each unit consists of both a GTG set and a STG set. The generators on the gas turbines are cooled with hydrogen, which is utilized as a cooling medium for a couple of key reasons. First, hydrogen has a superior heat transfer, compared to air, due to its thermal conductivity. Hydrogen is roughly seven times more conductive than air. Secondly, due to the low density of hydrogen, windage losses of the generator field are minimized. This allows the generators to remain compact and efficient. The hydrogen in the generator must be maintained at over 99% purity to prevent an explosive hydrogen/air mixture. The generator tends to lose hydrogen pressure during normal operations, so oil is used as a sealing barrier to prevent gas leakage from the generator. Some hydrogen also becomes entrained in the oil and is drained from the generator through the oil drains and that hydrogen is exhausted outside the plant. Due to this loss of hydrogen and other small miscellaneous leakages, a source of hydrogen must be on hand to replenish the used hydrogen preventing pressure decay and to maintain the purity in the generator;

- Small Site Capital (*Bridge Period*: $360,000 – *Test Year*: $270,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Covert during the projected bridge period and test year;

- Covert Base Outage Capital (*Bridge Period*: $480,000 – *Test Year*: $360,000) Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- During the bridge period, 25 additional projects at Covert totaling $3.336 million which support safety, security, and reliability, with each project representing $240,000 or less in capital expenditures. These projects include protective relays, heat trace panels, gas turbine evaporator media, plant fuel gas

bypass system, ammonia fan replacements, and Unit 1 Power Distribution Center ("PDC") battery replacement; and

- During the test year, 13 additional projects at Covert totaling $1.714 million which support safety, security, and reliability, with each project representing $307,064 or less in capital expenditures. These projects include HRSG Joint replacement, MS tee header replacements, Units 1 and 2 closed cooling pump/motor replacements, Continuous Emission Monitoring ("CEMS") Environmental Systems Corporation ("ESC") Spectrum 8864 datalogger replacements, condensate pump/motor replacements, and Lake pump Remote Terminal Unit ("RTU") Distributed Control System ("DCS") upgrade.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2027, and the projected test year ending April 30, 2028, for Karn Units 3 and 4.

A. At Karn Units 3 and 4, the Company plans to invest $14.211 million in the projected bridge period and $3.170 million in the projected test year, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected $14.211 million capital investment in the 16-month projected bridge period and $3.170 million in the projected test year?

A. The projected $14.211 million capital investment in the projected bridge period and $3.170 million in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects in the bridge period, and one project in the test year, which are greater than $1 million. These projects are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, lines 21 through 24 and page 9, line 18, respectively.

The basis for these projects is described below:

- Karn Unit 3 Combustion Air Heater replacement (*Bridge Period*: $2,250,001). The scope of this project is to replace the combustion air heater. The 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. The projected benefits include 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. The CAD for this project is attached as Exhibit A-208 (MEW-15) ;

- Karn Unit 4 Combustion Air Heater replacement (*Bridge Period*: $600,000 - *Test Year*: $2,733,000). The scope of this project is to replace the combustion air heater. The 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. The projected benefits include 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. The CAD for this project is attached as Exhibit A-208 (MEW-15);

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft ("ID") Fans to Stack (*Bridge Period*: $2,358,001). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance. The CAD for this project is attached as Exhibit A-209 (MEW-16);

- Karn Unit 4 Post-Transformer Fire Remediation (*Bridge Period*: $4,295,853). In the original Karn Units 3 and 4 plant design, startup transformer bank (#8), fed by the grid, is used to power up large fans and pumps until the unit is synchronized and starts, putting Megawatts out on the grid through the main GSU. At that point, the plant is switched over to feed its own power through the SPTs and Megawatt output may be increased to full load. During the 2025 Karn Unit 4 main GSU fire, the Unit 4 SPTs X, Y, and Z nearby also suffered damage. The bus connecting the SPTs to the plant was burned away. This bus

was attached to the transformers through porcelain terminal bushings, which busted as the bus fell. The internal windings of these three transformers tested ok after the fire, but the bushings need to be replaced to make them useable. Furthermore, the heat of the fire has deformed some of the oil seals on the transformers. During the winter, the Company implemented protective measures to stabilize the fire-damaged transformers and preserve the windings until permanent repairs can be completed. Although several oil seals were compromised, interim work allowed the units to remain in a safe, cold-standby condition. In the fall, the Company began procuring all necessary bushings, seals, and components for full restoration. Supply-chain delays have extended delivery of key high-voltage bushings into late 2026. However, during the winter the Company successfully installed new nitrogen-blanket systems on the transformers. These systems maintain a slight positive pressure to prevent air and moisture from entering the oil. Despite significant porcelain damage to the bushings, nitrogen consumption has been lower than expected, indicating the units are holding pressure effectively. Field crews addressed minor oil seepage at drain valves, and monitoring shows these leaks have stabilized. Some exterior wet spots remain under observation but are manageable while the units remain de-energized. Hitachi currently expects to deliver the high-voltage bushings in June. Upon delivery, Trans-Utility will mobilize to drain the transformer oil and replace the damaged components, allowing the restoration work to proceed. The #8 bank is sized to provide Unit 4 station power and start Karn Unit 3; however, it is not sized to provide station power for both units while online. Thus, Karn Unit 3 station power is critical to achieving full load. If one of Unit 3's SPTs failed, Karn Unit 3 would be derated half load until the failed transformer was replaced. Procuring a replacement transformer typically takes up to three years. Given the long lead times, continued operation under interim measures alone would not be a sustainable or prudent operating condition. The CAD for this project is attached as Exhibit A-210 (MEW-17);

- Karn Unit 4 ID Fan Inlet Damper Replacement (*Bridge Period*: $2,025,000). The Karn Unit 4 ID Fan dampers moved up in priority when they failed in place and became a broke/fix issue. The site made a temporary repair to keep the units available, but the equipment is beyond its serviceable life and will need replacement immediately to mitigate a major failure. With the age of the equipment, the Company does not have a repair option that will be permanent or long term, therefore replacement is the best option. The CAD for this project is attached as Exhibit A-211 (MEW-18).

The following projects are less than $1 million, but are important to reliability:

- Karn Unit 3 Residual Oil Heater Overhaul (*Bridge Period*: $495,000) The scope of this project is to install new tube bundles. The existing tube bundles have many leaks, and the heaters are no longer functioning and are cut out of the system;

- Karn Units 3 and 4 ID and Forced Draft ("FD") Fan Vibration Systems (*Bridge Period:* $730,000 each). The existing ID Fan vibration system at Karn Units 3 and 4 was originally designed only for monitoring and alarming, not for equipment protection. Following a catastrophic ID Fan failure in 2016, the system was modified to initiate fan trips based on vibration alarms. This retrofit approach has resulted in repeated false trips and unnecessary unit shutdowns, increasing operational risk and reducing reliability. This project replaces the current system with Emerson Ovation Machinery Health Monitor R-Line modules installed in a new remote I/O cabinet adjacent to the ID and FD Fans. The upgraded system will integrate directly with the existing Ovation Distributed Control System, provide API-670 compliant vibration protection, and support full waveform and waterfall vibration analysis. The scope includes 24 new vibration and speed sensors, buffered output splitters for portable analysis tools, and protection coverage for both ID and FD fans. The upgrade mitigates the significant risk of another catastrophic fan failure. This project improves safety, reduces false trips, enhances diagnostic capability, and eliminates the need for separate third-party systems, enabling synchronized software updates and consistent cybersecurity management;

- Karn Units 3 and 4 Small Site Capital (*Bridge Period*: $360,000 – *Test Year*: $270,000). This project supports capital expenditures for small capital tools/valve/instrumentation funds to cover broken/fix and priority 1 outage items at Karn during the projected bridge period and test year;

- Five additional projects in the projected bridge period totaling $367,040 which support safety, security, and reliability, with each project representing $180,000 or less in capital expenditures. These projects include Karn sync wire replacement, Karn Units 3 and 4 Tank Farm PLC/DCS replacement, and replacement of house service water ("HSW") piping on Karn Units 3 and 4; and

- Two additional projects in the projected test year totaling $166,585 which support reliability, with each project representing $99,085 or less in capital expenditures. These projects are for the Karn Thermo i-Series CEMS Analyzer replacements and HSW piping replacement.

<u>Zeeland Plant</u>

Q. Please explain the Company's projected investment for the 16-month projected bridge period ending April 30, 2027 and projected test year ending April 30, 2028 for the Zeeland Plant.

A. The Company plans to invest $49.037 million in the 16-month projected bridge period and $52.137 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12

(MEW-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by several short, 14-day outages on all Zeeland Units throughout the Spring and Fall of 2026 and 2027. These outages will accommodate turbines, water wash, and compressor inspections, as well as BOP repairs. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected $49.037 million capital investment in the 16-month projected bridge period and $52.137 million in the projected test year?

A. The projected $49.037 million capital investment in the projected bridge period and $52.137 million in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects in the bridge period, and seven projects in the test year, which are greater than $1 million. These projects are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, lines 16 through 20, and page 9, lines 11 through 17, respectively. The basis for these projects is described below:

- LTSA/Phase II Gas Turbine AGP Replacement and AFS (*Bridge Period*: $14,622,423 – *Test Year*: $18,052,064). Zeeland Generating Station is a gas-powered combustion turbine plant consisting of four gas turbines and one steam turbine. These turbines are covered by an LTSA with GE to provide overhauls and upkeep on the units to periodically restore them to like-new condition. Periodically, the units are shut down for a major outage that is performed by GE. Part of the major work executed during such outages is replacement of the "hot", or combustion, parts as they degrade over their 32,000-hour design life. During these outages is the ideal time to incorporate major work that will improve the performance and/or reliability of the unit. The two gas turbines at Zeeland Phase 2 have Major Inspection outages in 2028. This project is to implement upgraded replacement parts in both phase 2 gas turbines. One such performance improvement (while maintaining the same reliability) is called an AGP. The AGP package provides significant output and efficiency (heat rate) improvements by replacing the turbine and combustion parts with higher performing and more technologically advanced parts. An additional improvement (while maintaining the same reliability) is called AFS. The AFS package enables significant output turndown capability by replacing and adding

combustion hardware with more technologically advanced parts that enable lower load operation while maintaining emissions compliance. This technology is potentially key to the Zeeland Phase 2 plant's ability to be flexible in supporting Consumers Energy's new energy portfolio, where a dramatic increase in renewable energy will demand greater flexibility from the rest of the generating assets in the portfolio. The CAD for this project is attached as Exhibit A-212 (MEW-19);

- Zeeland Phase II Turbine Replacements (*Bridge Period*: $10,330,401 – *Test Year*: $12,026,598). The scope of this project replaces the existing rotor with a new rotor, giving another 144,000 hours of operation which would enable operation until the next rotor replacement out to approximately the year 2045. Also included in this scope are new compressor stator vanes due to the compressor being 20 years old; the best way to restore the compressor to like-new condition is to replace the stationaries when the blades will already be replaced. Lastly, the exhaust frame will be upgraded to a robust exhaust frame due to reliability issues over the years, and the rotor replacement being an appropriate time to replace the exhaust frame. The CAD for this project is attached as Exhibit A-213 (MEW-20);

- Zeeland Purchase of Site Spare GSU (*Bridge Period*: $4,584,810). The scope of this project is the procurement of a spare GSU for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSUs. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU would effectively limit operation of two connected combustion turbine units. The lead time for a GSU is currently three to four years and spare units at other facilities are not viable replacements due to compatibility and installation challenges. This project would purchase a spare GSU that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future. The CAD for this project is attached as Exhibit A-214 (MEW-21);

  - Zeeland Plant GE LTSA - Running Capital Contract (*Bridge Period:* $12,364,040 – *Test Year:* $9,574,921). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and,

as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. A confidential copy of this agreement has been attached as Exhibit A-215 (MEW-22)-CONF;

- Zeeland LTSA Owner Obligations (not included in contract) (*Bridge Period*: $144,000 - *Test Year:* $3,498,000). The LTSA owner obligation work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA. A confidential copy of this agreement has been attached as Exhibit A-215 (MEW-22)-CONF;

- Phase I and Phase II High Recovery Gas Valves (*Bridge Period:* $3,168,000 - *Test Year*: $1,080,000). GE discontinuing the existing valves forces the need to switch to valves that GE will support in the future to maintain units' reliability and maintenance costs. Additionally, the Consumers Energy Fossil Fuel Supply group attempted to quantify the dollar impact that low gas supply pressure events had caused in the years 2023 and 2024 using Generating Availability Data System ("GADS") data. GADS data does not tell the entire story of these events as it only shows events where the supply pressure was bad enough to warrant entering a derate and when the units were generating lower than their day-ahead bid capacity. If all low supply events could be added up (and the effects of not being able to supply/sell power above the day-ahead bid capacity), the costs would likely be much higher. However, the Fossil Fuel Supply group did figure around a $350k real dollar impact over the course of the two years (2023-2024), with the potential of around $4 million of impact should the Real-Time locational marginal price be at a higher point when these events occur. Spring 2027 – Valves are flanged, so the replacement should only take 2 to 3 weeks, but ZGS typically only takes 10-15 day outages. Spring 2027 is a 55-day outage and the next long-duration outage won't be until 2032 timeframe. Additionally, the Spring 2028 Outage is the ideal outage of opportunity as the Phase 2 Spring outage is the Major Inspection and AGP/AFS Upgrade Outage when these valves will be overhauled or replaced anyway, and the Phase 1 valves could be replaced during their normal Spring outages just a week before the Phase 2 outage. To align the Phase 1 and Phase 2 gas valves replacements occurring very near the same time is important as the units with the new gas valves will draw more gas and causing the units without the new gas valves to be "robbed" of gas supply (and therefore, potentially, capability) during low pressure events. The CAD for this project is attached as Exhibit A-216 (MEW-23);

- Zeeland 2C Field Exchange and Generator Major Overhaul (*Bridge Period*: $300,084 – *Test Year*: $1,734,000). Based on GE inspections and testing, the generator exhibits early indicators of rotor and stator degradation, including a

confirmed shorted turn in the generator field, dust accumulation on stator components, and abnormal collector ring wear. These conditions increase electrical and mechanical stress, elevate vibration and thermal risk, and could impair the unit's ability to reliably maintain voltage and capacity if left unaddressed. GE has indicated deterioration is expected to progress by 2028. The planned work mitigates reliability, performance, and forced-outage risk and supports continued safe and dependable operation of the unit. The CAD for this project is attached as Exhibit A-217 (MEW-24); and

- MS & Hot Reheat Isolation Valves Replacement (*Test Year*: $1,050,351). During the Fall 2023 Steam Turbine Minor Inspection outage at the ZGS, a roughly 2.5" x 0.5" piece of stellite was found in the MS strainer, which is just upstream of the MS Stop/Control Valves. The only potential areas from where this stellite could have originated is either the 2A or 2B MS Non-Return Valves ("NRVs") or the 2A or 2B MS Stop Isolation Valves. The MS NRVs were already planned for replacement for other reliability reasons during the Fall 2024 Outage, which was complete. When the valves were removed from 2A and 2B, they were inspected to find no evidence of failure of the stellite seat and trim. That leaves the origination of the stellite piece found in the Fall 2023 Outage as coming from the 2A or 2B MS Stop Isolation Valves. Upon further investigation, numerous valve vendors confirmed that the industry has seen many failures of stellite delaminating from a valve body's parent metal to be sent to the downstream Stop/Control Valves. The strainer should catch these potential pieces, but in at least one case in the power industry, a piece wore a hole through the strainer, sending it to the Steam Turbine path causing significant Domestic Object Damage, requiring immediate shutdown and lengthy repairs for that unit. The CAD for this project is attached as Exhibit A-218 (MEW-25).

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Small Site Capital (*Bridge Period*: $360,000 – *Test Year*: $270,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Zeeland during the projected test year;

- Phase II Feedpump Hydraulic Coupling Replacement (*Bridge Period*: $202,500 – *Test Year*: $405,000). The ZGS Phase 2 Plant (commissioned in the early 2000s) is a natural gas combined cycle plant that requires large pumps/motors for pumping feedwater ("FW") to the HRSGs. The plant is a 2-on-1 combined cycle unit, meaning *two* gas turbines exhaust to respective HRSGs which generate steam for *one* steam turbine. The site can operate in 1-on-1 if needed (*one* gas turbine exhausting to respective HRSG to generate steam for the *one* steam turbine). Each HRSG has two 100% feedpump trains (i.e. one is redundant), and operation is swapped between the two to maintain similar operating hours. Thus, in total, there are four such pumps/motors, and each one

has a hydraulic coupling to transfer the constant motor speed to the pump speed required by the HRSG. The replacement cycle for these hydraulic couplings should be approximately every seven years according to the manufacturer manual, and some of the couplings have never been replaced (only have a record of two being overhauled in 2018). The ideal time to do the coupling replacements would be at the same time the next cycle of feedpump replacements begins (2027), where one feedpump is replaced with the spare feedpump per year for four years (2030 would be the final feedpump replacement in the upcoming cycle). The site has a brand new spare hydraulic coupling that will need to be pulled out of stock for the first feedpump replacement. This will enable the subsequent hydraulic coupling replacements as part of the annual feedpump replacement cycle;

- Zeeland Compressed Air System Replacement (*Bridge Period*: $648,000). The Zeeland Generating Station utilizes compressed air for a variety of pneumatic-controlled devices and tools. The air compressors in Phase 1 and Phase 2 have historically been unreliable, lacking redundancy. Although the systems of both phases are interconnected, allowing one to back up the other, they are nearly at capacity during normal operations, leaving insufficient air capacity to support both phases simultaneously. There is, however, room to introduce redundancy into both phases. Achieving redundancy in both would, with the existing interconnection, elevate the system to triple redundancy, a level befitting the critical nature of compressed air for plant operations, reliability, safety, and equipment protection. The current air compressors do not meet ISO 8573-1 Class 0 standards, meaning they are not oil-free, leading to oil contamination in the air dryers. This contamination has caused inadequate moisture removal, resulting in freezing issues within the air system and its components. Such freezing can impede operations, sometimes preventing power generation. For instance, in February 2023, freezing in an air-operated regulator limited the duct firing capacity. Moisture-related issues have been a recurring problem annually. Another issue is the exclusive maintenance agreement between Atlas Copco and Air Technologies, which has proven unreliable at times. Plant Operations can handle most maintenance and repair tasks for the compressed air system. Moreover, Atlas Copco's proprietary communication protocol has presented ongoing setup challenges;

- Zeeland Plant Base Outage Capital (*Bridge Period*: $510,000 – *Test Year*: $382,500). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages at Zeeland;

- Combined Cycle SCR Catalyst Replacement (*Bridge Period*: $30,843 - *Test Year*: $709,394). The ZGS uses a SCR system to reduce the Nitrous Oxides (NO_x) in the flue gas from the combustion process down to emission-compliant levels prior to exhausting out the stacks of both HRSGs. The catalyst health has been monitored closely since replacement in 2012, and the catalyst is nearing end-of-life. The catalyst life will be exhausted shortly after this outage, and the

Spring 2028 outage is 55 days providing plenty of time for changeout. The changeout for each unit may be able to be moved to 2027 depending on if the outage duration could be extended greater than the 14-day outage currently scheduled. Asset Health Department has been monitoring the health of the catalyst using yearly testing and every other year physical catalyst samples (and lab testing) to determine the predicted end of life;

- Zeeland Phase 2 FW Pump Isolation Valve (*Test Year:* $440,279). The Phase 2 ZGS has two HRSGs, both of which have two 100% FW Pumps for redundancy. All four ZGS FW Pumps have isolation valves on the Suction, HP discharge, and Intermediate Pressure ("IP") discharge piping. These isolation valves (if holding tight) enable a feedpump to be isolated in case of emergent work while the redundant pump maintains the pumping requirements for the HRSG. The isolation valves around the FW Pumps are original to the plant (20+ years old), not fully isolating, needing to be replaced. Additionally, the valves are in difficult-to-access areas and new valves should have motor operators added to make them Motor Operated Valves ("MOVs") as the existing valves present significant safety concern to operate. This would also require control changes to enable remote control of the MOVs;

- Zeeland 177, 277, 500 345 kV Breaker Replacement (*Bridge Period:* $30,000 - *Test Year*: $900,000). The installed Hitachi High Voltage Breaker ("HVB") breakers have a critical design flaw where individual poles may not latch open when required. This has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or generator damage. Historical data and recent maintenance have allowed engineering to identify key design flaws in the base design of the HVB Hitachi breakers, where individual poles may re-close after a trip event. The breaker's locking latch design, when in the open position, has been found to be unreliable, and the breaker's drive mechanism does not move all poles at once, allowing individual phases to re-close unexpectedly if the lock latch does not move into the correct position. Engineering understands that this design cannot be altered as-is, and the equipment must be replaced to mitigate this issue. This is a known industry problem since the early 2000s. ITC has replaced most of the HVB breakers within the transmission system. In November 2019, breaker 299 failed to close on the X phase. The problem was identified as the crankshaft being bound in the brass bushing. The grease was dry and did not allow the parts to move with respect to one another. The crankshaft is part of the breaker closing mechanism and had failed in service. In November 2018, breaker 699 failed to open, where one of the poles remained closed when the breaker attempted to trip. The condition persisted for 3 minutes and potentially could have caused undesired heating effects on the low voltage winding of the 2C GSU;

- In the bridge period, 16 additional projects at the Zeeland Plant totaling $1.432 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $310,000 or less in expenditures. These projects include Zeeland 1B Excitation Replacement

Transformer, Zeeland Combustion Turbine ("CT") Transformer replacement, Zeeland Phase I Closed Cooling Water Heat Exchangers ("CCW HXs") Foggers, Zeeland Cooling Tower siding; and

- In the test year, fifteen additional projects at the Zeeland Plant totaling $2.014 million support reliability and operations, with each project representing $240,000 or less in expenditures. These projects include Phase 2 Bentley Nevada vibration monitoring unit replacement, Phase 2 Duct Burner Diffusers Enhancement, Phase 1 and Phase 2 Gas Turbine ("GT") Evaporative Cooler Media Replacement, Phase 2 Battery Charger and Inverter Replacement.

Jackson Plant

Q. Please explain the Company's projected investment for the 16-month bridge period ending April 30, 2027 and test year ending April 30, 2028 for the Jackson Plant.

A. The Company plans to invest $35.343 million in the 16-month projected bridge period and $25.733 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the Spring of 2026 and 2027. The Company has an LTSA with GE to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected $35.6343 million capital investment in the 16-month projected bridge period and $25.733 million in the projected test year?

A. The projected $35.343 million capital investment in the 16-month projected bridge period, and $25.733 million in the projected test year, will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects in the bridge period, and four within the test year, which are greater than $1 million, and they are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, lines 11 through 15, and page 9, lines 7 through 10, respectively. The basis for these projects is described below:

- Jackson Plant LTSA Spend with GE (*Bridge Period:* $17,010,000 – *Test Year*: $13,450,500). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support

services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. Confidential copies of these agreements have been attached as Exhibit A-219 (MEW-26)-CONF through Exhibit A-223 (MEW-30)-CONF;

- Jackson Plant LTSA Historical Owner Obligations (*Bridge Period*: $7,236,727 – *Test Year*: $915,000). LTSA owner obligations are a required and recurring component of major turbine-generator outages at the Jackson Generating Station and are necessary to execute the OEM-defined LTSA work scope. While these activities are not included in the base LTSA contract, they are explicitly part of the Owner's responsibilities under the LTSA division of responsibility and are unavoidable to support inspections, disassembly, repairs, and reassembly. These obligations include owner-furnished infrastructure and logistical support such as cranes, scaffolding, laydown and rigging areas, temporary facilities, utilities, equipment transport, and plant modifications needed to access major components. Without these enabling activities, the contracted LTSA work cannot be safely or effectively performed. These costs are inherent to executing major outages on aging assets, have been consistently incurred in prior Jackson outages, and are necessary to return the units to safe, reliable, and compliant operation. As such, LTSA owner obligation costs represent prudent, non-discretionary expenditures required to maintain the long-term reliability and performance of the Jackson units. Confidential copies of these agreements have been attached as Exhibit A-219 (MEW-26)-CONF through Exhibit A-223 (MEW-30)-CONF;

- GSU Transformer Site Spare (*Bridge Period*: $1,160,000 – *Test Year*: $2,000,000). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure in delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three to four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell, Karn, Lake winds, and Crosswinds do not have the correct voltage (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to function at Jackson so they cannot be considered for use as spares. The CAD for this project is attached as Exhibit A-224 (MEW-31);

- Jackson Plant LM1-6 VIGV (*Bridge Period*: $1,274,013 – *Test Year*: $756,288). This project will install new VIGV systems on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC engine has a partial installation already, and the project will complete the VIGV system for this engine. For LM6000PC SPRINT gas turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel efficiency improvement at part power. The average fuel efficiency improvement at 70% of maximum power is greater than 2%. The VIGV also helps minimize variable bypass valve ("VBV") flow and pressure levels, thereby reducing associated flow noise. The VIGV system improves performance for both simple cycle and heat-recovery cycles when operating at less than full load. The CAD for this project is attached as Exhibit A-225 (MEW-32);

- Jackson Unit 7 Gas Turbine Rotor Replacement (*Bridge Period:* $2,127,333 – *Test Year*: $1,494,667). The scope of this project is to replace the Unit 7 Gas Turbine Rotor as it is essential to prevent high-probability failures, ensure continued operation, and avoid significant downtime. This investment will provide long-term reliability and efficiency for the plant's operations, ensuring optimal performance of the gas turbine. The Jackson Generating Station Unit 7 Gas Turbine Rotor Replacement project is a critical initiative aimed at ensuring the continued operation and efficiency of the GE 7EA gas turbine. The rotor for this turbine has a life limit of either 5,000 starts or 250,000 running hours. A new rotor will take approximately two years to be delivered after the order. The CAD for this project is attached as Exhibit A-226 (MEW-33); and

- Main and Auxiliary Cooling Tower Rebuilds (*Bridge Period*: $387,529 – *Test Year*: $2,307,980). Jackson Generating Station has a circulating water system comprised of a single eight-cell induced draft, counterflow cooling tower, and an auxiliary cooling water system that has a two-cell induced draft, counterflow cooling tower. Each tower consists of a pressure treated Douglas fir structure with PVC fill and drift eliminators, a fan deck made of pressure treated tongue and groove plywood, cell partitions, windwalls made of pressure treated Douglas fir plywood, and fiberglass reinforced plastic pipe headers with PVC lateral distribution systems. The current cooling towers have been in service for 22 years with no planned or major maintenance performed during that time. The Douglas fir components are delaminating and deteriorating from the wear and tear of the water and the chemical used in the water. A complete cooling tower health assessment was performed in Fall 2024. The CAD for this project is attached as Exhibit A-227 (MEW-34).

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Reverse Osmosis Pump Replacements (Bridge Period: $246,235 - *Test Year:* $492,470). JGS utilizes well water and sometimes municipal water (city water) which is processed by the reverse osmosis ("RO") system to provide condensate

quality water to various systems in the plant's steam cycle including the plant's steam injection system and seven HRSGs as makeup water. The plant has two RO skids (Train A and Train B) that are standalone and utilize horizontal pumps to provide a capacity of 225 gpm each. The plant's third RO skid (Train C) is standalone that was installed in 2019 and utilizes vertical pumps to provide a capacity of 300 gpm. The pumps on trains A and B have a history of failures ranging from bent shafts to sheared shafts. The original pump manufacturer has a history of long lead times on parts and rebuilds the pumps are failing on an average of 1 to 3 failures per year. The pump failures cause operational limitations due to the lack of redundancy in maintaining a sufficient water level in the makeup tank (demineralized water tank) while providing makeup water to the various steam systems; the new pumps will reduce the amount of premature failures, and the newer design and components are more readily available if repairs or pumps are required in the future;

- LM6000 ESN 191-307 HP Turbine S1 Blade replacement (*Bridge Period*: $716,334 – *Test Year*: $91,219) There are three LM6000 GTs at JGS that are currently experiencing burn through on their High-Pressure Turbine ("HPT") S1B. Burn through represents the loss of a protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GT's that are experiencing this condition are indicated by their Engine Serial Number ("ESN"), ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual Borescope Inspections ("BSI") of all the JGS LM6000 GT's that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

  The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1B's, and returned to JGS. The set of HPT S1B's pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1B's pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1B's pulled from the third GT will be overhauled and returned to JGS to be used for future needs. This blade replacement must be completed in order to perform the subsequent LM6000 HP Turbine S1 Blade Overhaul project;

- LM6000 HP Turbine S1 Blade Overhaul (*Bridge Period*: $817,859). This project is the second phase of the previously discussed project. There are three of six LM6000 GT at JGS that are experiencing deterioration of their HPT S1B from normal operation. The HPT S1Bs are experiencing burn through which is described as the loss of the protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the

OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs of concern will go through a sequence of replacing the HPT S1B, once the third GT is complete there will be a set of HPT S1B that will need to be overhauled for availability to the next LM6000 GT that requires the same blade set. This project is to capture the cost of the blade overhaul following the third LM6000 GT HPT S1B replacement;

- Jackson 735 Breaker Relay Replacements (*Bridge Period*: $384,300). The Company is experiencing failures of the GE Multilin 735 relays that provide overcurrent protection to a large motor failed in service. This model of relay is no longer available. There are five of these relays at the Jackson plant. When another one fails, the motor will be forced out of service for a long duration while relays of a different manufacturer are installed. If one of these relays fails it will cause a derate, the derate will be higher in the summer than the winter months. System protection recommends install of a SEL-551C and a BE1-851 as replacement;

- Small Site Capital (*Bridge Period*: $360,000 – *Test Year*: $270,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Jackson during the projected test year;

- Base Outage Capital (*Bridge Period*: $360,000 – *Test Year*: $270,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- Jackson 7 Advanced E-Class Model ("EA") Exhaust Frame with diffuser (*Bridge Period*: $439,081 - *Test Year:* $623,700). Since their introduction in 1978, advances in materials, cooling, and design have allowed GE gas turbines to operate with increased firing temperatures and airflows. These advances have resulted in elevated exhaust temperatures and increased aero loading that affect the strength of exhaust systems during turbine startup, operation, and shut down. These units have high transient thermal stresses and aero loading that come with turbine uprates. This generates raised fatigue stress that can significantly increase cracking in exhaust systems. The 7EA turbine's exhaust frame directs high temperature exhaust gas from turbine outlet into the exhaust plenum. It consists of an inner diffuser, an outer diffuser, and a turning vane sub-assembly. JGS's diffuser assembly had a history of cracking prior to its 2018 major outage inspection. As in previous cracking events, weld repairs were made during 2018 outage in accordance with recommendations from GE Power Answer Center ("PAC") cases that were initiated during the outage. JGS's hot gas path parts were upgraded in 2018 to achieve a higher firing temperature of 2055° F. According to GE GER-4610 (Exhaust System Upgrade Options for Heavy Duty Gas Turbines), uprating the unit to a higher firing temperature which increases exhaust temperatures. GE advises replacing the exhaust frame assembly with another assembly capable of higher temperatures.

The JGS exhaust frame and diffuser were not upgraded. Installing an assembly capable of higher temperatures is advised if the installed frame has suffered damage due to its lower temperature capability in an elevated temperature environment;

- Jackson 7EA Compressor Casing Replacement (*Bridge Period*: $286,388 - *Test Year:* $553,946). During the 2018 major outage inspection there were tight clearances between the compressor stators and the turbine rotor. Blade tip grinding, blade and stator blending were performed in accordance with recommendations from GE PAC cases that initiated during the outage to return rotating-to-stationary component clearances to in-service allowable state, at a minimum, to return the unit to service. There were indications of smeared metal deposits in all 17 stages of compressor casings. The 2018 major outage inspection recommended that the stage 17 stationary blading be replaced during the next major inspection which is in 2029. Corrosion/oxidation has been noted throughout the aft stages of the compressor during annual borescope inspections. Blading rubs can be caused by casing distortion that progresses over time, and by hot restarts initiated between one and eight hours after shutdown. Corrosion pitting can create a local stress concentration that may result in tip loss due to high cycle fatigue;

- Jackson Fire System Replacement (*Bridge Period*: $369,900) The site's existing fire system was obsolete and has experienced multiple failures over the last 24 months. These failures significantly impacted the site by accidentally dumping the system into the cooling tower and fouling the system leading to service disruptions and added expense to clean up the false release. A fire system replacement will upgrade the entire site to the latest Siemens equipment, with a minimum of 10 years of planned support. This approach ensures the work scope corrects all deficiencies, significantly reduces the risk of future system failures and brings the site up to code;

- Seventeen projects in the projected bridge period, totaling $2.168 million, with each individual project representing $318,600 or less in expenditures. These projects include JGS Low Pressure ("LP") Pegging Valves, JGS Chiller D Compressor #1 and Compressor #2, 269 Breaker Relay Replacements, Major Motor and Pump Replacements; and

- Eighteen additional projects in the projected test year totaling $2.507 million, with each individual project representing $345,858 or less in expenditures. These projects include Emergency Diesel Generator Electrical Load Bank, Steam Turbine 8 and Turbine 9 Spill Strip and Gland Packing Replacement, Steam Turbine 8 and Turbine 9 Blade Replacements.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2027, and the projected test year ending April 30, 2028, for the Hydro Units.

A. The Company is not presenting any capital investments during the 16-month bridge period or projected test year on the Hydro Units, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 3, line 50, columns (h) and (j), respectively. The Company is requesting continued deferral treatment as discussed in more detail in the direct testimony of Company witness Myers.

Ludington Pumped Storage

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2027, and the projected test year ending April 30, 2028, for the LPS.

A. The Company plans to invest $29.603 million in the 16-month projected bridge period and $29.552 million in the projected test year in the LPS, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 3, line 57, columns (h) and (j), respectively. These capital investments will be implemented during periodic outages in 2026 through 2028. It is important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023, Order in Case No. U-21310.

Q. What is the basis for the projected $29.603 million capital investment in the 16-month projected bridge period and $29.552 million in the projected test year?

A. The projected $29.603 million capital investment in the 16-month projected bridge period, and $29.552 million in the projected test year, will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are eight projects in the bridge period, and six projects in the test year, which are greater than $1 million, and they are presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, lines 25 to 32 and page 9, lines 19 to 24. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement (*Bridge Period*: $4,301,715 – *Test Year*: $2,131,884). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic I/O modules and new relays where needed. The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

  The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

  The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end- of-life of the units and needs to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System ("DAS"), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the

infrastructure to build upon for full site/unit control at LPS. The CAD for this project is attached as Exhibit A-228 (MEW-35);

- Ludington 1 Pony Motor Replacement (*Bridge Period*: $3,870,000 – *Test Year*: $3,270,000). The project will remove and replace the existing pony motor rotors with new rotors that will provide another 50 years of service. It is assumed that the stators on both units can be reused, and that the new rotor will be designed to work with the existing stator and liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no longer an issue for the remaining life of the plant. During the overhaul of Unit 1 (performed by Toshiba in 2018 and 2019), an NDE test performed on the pony motor rotor structure recorded linear indications, a.k.a. cracks, in presumed high stress locations. Prior to re-assembly after the major overhaul work, the linear indications had been repaired by Toshiba. The unit experienced problems with fastener failures after being returned to service, and subsequent inspections identified that the linear indications (cracks) returned, and that the indications continued to grow in volume and size with use of the pony motor. Unit 1's pony motor was subsequently removed from service and the indications continue to be tracked with regular inspections. Since the pony motor is no longer used to start the unit in pump mode, the indications have not grown, nor have new indications been noted. Analysis acquired has subsequently shown that the rotor material is beyond its fatigue life limit, which explains the continued crack growth with Unit 1's pony motor use. The major risk is that if cracks begin to grow again, the whole unit must be taken off line to protect the rest of the unit from failure. The pony motor will remain unavailable to start the unit as a pump until the pony motor rotor is replaced. The CAD for this project is attached as confidential Exhibit A-229 (MEW-36)-CONF;

- LPS Units 2 and 4 Head Cover and Bottom Ring Replacement (*Bridge Period:* $5,676,000 – *Test Year:* $9,900,000). The Head Covers and Bottom Rings on Units 2 and 4 at the Ludington Pumped Storage Facility must be replaced to address long-term structural and reliability risks identified through recent finite element and fatigue analyses. While these components do not pose an immediate safety or operational concern, the analyses show they are unlikely to meet the intended service life of the new discharge ring components that must be installed to correct defective work performed during earlier overhaul activities.

This replacement work is critical because Units 2 and 4 must already undergo complete disassembly as part of the Corrective Work Project. That outage provides the only practical, cost-effective opportunity to address the long-term degradation risks of the Head Covers and Bottom Rings without triggering major future disassembly outages of similar scale. Missing this window would cause the cost of future replacement to increase dramatically and would expose the units to premature forced outages.

Alternative evaluations show that attempting to refurbish the existing components would place approximately 180 days of repair work per unit on the outage critical path, significantly extending the outage duration and increasing replacement power and capacity costs. Purchasing new components avoids these delays, ensures compatibility with the new discharge ring system, and provides a reliable 50-year service life.

Selecting new components for both units:

- Eliminates the risk of extended or unplanned outages during corrective work
- Addresses known long-term fatigue risks
- Aligns component life with the new discharge ring system (30+ years)
- Reduces long-term operational risk and mitigates major future costs
- Ensures unit reassembly can be scheduled efficiently and predictably

This project is a prudent investment that leverages a unique opportunity created by the corrective work outages. It replaces components with known long-term risks while the units are already fully disassembled, protecting customers from higher replacement power costs, avoiding significant future outage risk, and ensuring the long-term reliability of two critical generating units. The CAD for this project is attached as confidential Exhibit A-230 (MEW-37)-CONF;

- LPS Administration Building (*Bridge Period:* $3,500,000 - *Test Year:* $5,400,000). The Ludington Pumped Storage Administration Building is essential for Site Operations but faces critical issues due to deteriorating administrative infrastructure. A new permanent administration building is proposed to address operational, safety, and cost concerns. The proposed new administration building would eliminate recurring trailer costs, avoid replacement cycles, and improve safety and efficiency. This option presents the lowest lifecycle cost compared to ongoing trailer use. Operational and collaborative advantages include a consolidated, modern facility, which will enhance communication, increased safety oversight, and productivity, featuring large conference rooms, centralized IT, compliant restrooms, reliable utilities, and visitor-ready spaces for project teams and training. The CAD for this project is attached as Exhibit A-231 (MEW-38);

- Replace 480V DLCs (*Bridge Period*: $1,922,284 – *Test Year*: $1,558,481). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner

from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance. The CAD for this project is attached as Exhibit A-232 (MEW-39);

- Governor Replacement (*Bridge Period*: $3,095,253 – *Test Year*: $2,559,641). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear. The CAD for this project is attached as Exhibit A-233 (MEW-40);

- LPS Intake Gate and Gate House (*Bridge Period:* $1,516,302 – *Test Year:* $945,766). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option. The CAD for this project is attached as Exhibit A-234 (MEW-41); and

- Ludington SPT Life Cycle Management (*Bridge Period*: $1,380,000 – *Test Year*: $960,000). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare. The CAD for this project is attached as Exhibit A-235 (MEW-42).

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Generator Potential Transformer ("PT") and Enclosure Project (*Bridge Period*: $697,002 – *Test Year*: $647,657). Each LPS Unit utilizes six PT for Unit metering and regulating. A PT converts high primary voltage into a measurable low secondary voltage. The Metering PTs are utilized for indication of the Unit I/O and for the Disturbance Monitoring Equipment ("DME"). The Regulating PTs are utilized for Unit control and protection schemes. The current Unit metering and regulating PTs are plant original and have surpassed their life expectancy of 20-30 years. Occasionally, there have been unexplainable Unit trips due to a "PT Fail" alarm captured by the unit Exciters. This could be caused by a PT starting to fail. Most PT casings show their age in the form of cracks and separation of the molded casing. This can allow moisture ingress and internal insulating material loss. This can cause corrosion and overheating, ultimately leading to failure of the PT. The PTs are unlikely to last another 5-10 years and are suspected in the unexplained Unit trips. The PT enclosures are also original to the plant. There are three enclosures per unit, one for each phase (X,Y,Z). Each of the enclosures houses two drawers for the PTs, one regulating and one metering PT. The drawers have become difficult to open and close due to worn hardware. The enclosures also create a section of Isophase Phase Bus ("IPB") Duct for the IPB that connects the unit to the Starting Bus. This section of IPB Duct has been showing signs of damage due to eddy currents. This area is also a common Temporary Ground locations for workers protection during Unit and Starting Bus maintenance. The enclosure doors, where temporary grounds are installed, utilize an insert and bolt. These inserts increasingly become dislodged and fall into the Starting Bus. This causes emergent Working Clearance requirements to retrieve the inserts, so damage can't be caused by these inserts. Once an insert becomes dislodged, the insert hole becomes enlarged, and the insert can't be re-installed;

- Replace Barrier Net Panels (*Bridge Period*: $413,100 – *Test Year*: $413,100). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required;

- Twenty-three additional projects during the projected bridge period totaling $2.592 million, with each individual project representing $290,750 or less in expenditures. These projects include LPS Intake Transformer and Breaker replacement, LPS Corrugated Drain #17 replacement, and Unit Turbine Guide Bearing replacements; and

- Eighteen additional projects at Ludington totaling $1.765 million, with each individual project representing $321,750 or less in capital expenditures. These projects include LPS Replacement 4160V 1200A Powell Bus Break, LPS Commons AC & DC Distribution Panel Replacement, LPS Site Commons Barrier Net Crate Replacements, and LPS Synchronizer Relay Replacement.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2027, and the projected test year ending April 30, 2028, for Administrative and Other.

A. The Company plans to invest $12.093 million in the 16-month projected bridge period and $5.240 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected $12.093 million capital investment in the 16-month projected bridge period and $5.240 million in the projected test year for Administrative and Other?

A. The projected $12.093 million capital investment in the 16-month projected bridge period and $5.240 million in the test year will fund environmental, reliability, and infrastructure projects. There is one project in both the bridge period and test year, which is greater than $1 million and is presented on Exhibit A-12 (MEW-3), Schedule B-5.2, page 8, line 33 and page 9, line 25, respectively. The basis for that project is described below:

- JHC Wastewater Treatment System (*Bridge Period:* $10,516,667 – *Test Year:* $4,166,666). The Company considered several options for the treatment of wastewater that will continue to be generated at the Campbell site following cessation of coal generation, which was previously scheduled for May 2025. Options considered were transport for offsite disposal, offsite treatment, on site treatment and onsite disposal. Ultimately, on-site disposal via a deep injection well was selected and the Company filed for permits with EGLE, EPA, and NPDES, and began the project. Due to the DOE Orders to continue operating Campbell, the Company had to determine the most economical stopping point, in which to pause the project, which is after the completion of drilling the well. The planned structure at the site will not move forward until a later date, yet to be determined.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Small Tools and Equipment Lab Services (*Bridge Period*: $933,333 – *Test Year*: $700,000). Site Small Capital is a funding provided to each site to fund emergent broke/fix needs at the site level and approved by the site manager or delegate. This reserve funding mitigates smaller size change log requests and allows the plant to manage day to day issues and be more agile. Site Small Capital can be used to replace such things as valves, pumps, motors, instrumentation, tooling and other miscellaneous items at the site that meet the property accounting rules for capital. The Business Planning and Administration ("BP&A") analyst assigned at the site will review the requests for proper determination or help facilitate a decision from Property Accounting. The site manager or delegate ensures the Company is spending these funds prudently utilizing customer value as a key driver to prioritize the spending of this account;

- In addition to the project above, there are seven additional projects in the bridge period totaling $643,203. These projects include generation cyber security, laptop and capital business tool purchases for, Electric Supply, Environmental Services, Lab Services, BP&A, and Enterprise Project Management; and

- In addition to the project described above, there are six additional projects in the test year totaling $373,225. These projects include generation cyber security, laptop and capital business tool purchases for Electric Supply, Environmental Services, Lab Services, BP&A, and Enterprise Project Management.

BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2027, for BESS.

A. The Company plans to invest $34.408 million in the 16-month projected bridge period in Company-owned battery resources, as shown on Exhibit A-12 (MEW-3), Schedule B-5.2, page 3, line 71, column (h).

Q. What is the basis for the projected $34.408 million capital investment in the 16-month projected bridge?

A. The projected $34.408 million capital investment in the 16-month projected bridge period will fund two Company-owned BESS projects, Iosco and Weadock. The projects which are each greater than $1 million are presented on Exhibit A-12 (MEW-3), Schedule B-5.2,

page 8, lines 34 and 35. The basis for these projects is described in the direct testimony of Company witness Clark.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance and thus are not discretionary. Company witnesses Clark provides additional discussion in his direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily O&M of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy

Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, Lean Organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-197 (MEW-4), page 1, Generation O&M Expenses.

A. Exhibit A-197 (MEW-4), page 1, identifies the actual 2025 Generation O&M expenses, as well as projected expenses for the Test Year, 12-Months-Ending April 30, 2028. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2025 Generation O&M expense as $111.407 million; and
- Column (c) identifies the Projected Test Year Generation O&M expense as $102.482 million.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history of each generating unit and projects the future maintenance needs of each. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Operation Engineering organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – "Base," "Environmental Operations," "Major Maintenance," and "Retention and Separation."

Q. What are Base O&M expenses?

A. Base O&M expense comprises two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company's generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to (1) fuel (diesel and gasoline) for equipment and vehicles, (2) material, (3) tools, (4) cleaning supplies, (5) facilities, (6) security, and (7) road and grounds maintenance.

Q. Please explain how the 2025 Actual O&M expenses were developed.

A. The 2025 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the projected test year Base O&M expense was determined.

A. Base O&M expenses for the projected test year ending April 30, 2028, shown on Exhibit A-197 (MEW-4), page 1, line 1, column (c), were determined by considering staffing levels and historical spending. Total O&M expense for the historic year and the projected test year demonstrates average annual decreases of approximately 9.3%. As discussed later in this direct testimony, this average annual decrease primarily reflects a change in the mix of the Company's owned generating assets including the movement of renewable energy resources to the Company's renewable energy plans. Exhibit A-197 (MEW-4), page 1,

lines 2 and 3, identify the Environmental Operations and Major Maintenance expenses, which are variable O&M expenses and are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers.

Q. How do the historical and projected test year O&M expense amounts compare to prior years?

A. The 2025 historical O&M expense amount of $111.407 million and the projected test year O&M expense amount of $102.482 million compare quite favorably to the actual O&M expense amount for 2024 of $128.438 million. As stated throughout this testimony, the O&M expense reductions reflect a mix of generation asset changes, changes in major maintenance projects and expenses, cost recovery realignment, waste reduction measures, the current operational status of Campbell, and continued deferral of Hydro O&M.

Q. What is Emergent Reliability Funding ("ERF")?

A. ERF expense is a component of the Company's Admin/Generation Commons expense, which is itself a component of the Base O&M expense category. It represents an allocation of O&M funding designated for electric generation sites to address unforeseen reliability issues that arise during the test year. These emergent items are not included in detailed maintenance due to their unpredictable nature. Examples include unplanned equipment failures, urgent environmental compliance needs, or other reliability related corrective actions that are critical to maintaining safe and reliable generation operations. The total included in the Base O&M for the Test Year ending April 30, 2028 is $2.1 million. ERF is not a new funding item; rather, it is budgeted annually and is necessary in the test year

to fund emergent issues as they arise. The inclusion of this funding in the test year is necessary to ensure that electric generation sites maintain high reliability standards despite the inherent uncertainty of emergent issues. As generation assets age and operational demands evolve, the likelihood of unplanned reliability events increases. This funding provides flexibility to address such events promptly, ensuring compliance, safety, and service reliability for customers.

Q. Why is the Company specifically addressing ERF expense in this case?

A. In its March 27, 2026 Order in Case No. U-21870, page 326, the Commission directed Consumers Energy to provide a detailed explanation of how expenses associated with ERF are spent in the historical year. This testimony responds to that Commission directive.

Q. Please explain how the Test Year ERF expenses were developed.

A. The projected test year O&M expenses are developed based on the identified maintenance and reliability needs of each generating site and specific generating units for the projected test year. While historical ERF expenses are reflected in historical O&M, those historical amounts are not used as inputs to develop projected test year O&M expenses and therefore cannot be double counted in the test year forecast. The average ERF spent from 2022-2025 is $8.94 million/year.

Q. Please explain what was spent on ERF during the 12 months ended December 31, 2025.

A. During the 12 months ending December 31, 2025, Consumers Energy spent $12.05 million on ERF requests, in which there was a total of 48 requests. The major contributors (>$1 million) were the Karn Transformer fire ($5.5 million) and the Covert HEPS and Flow-Accelerated Corrosion ("FAC") major findings ($1.7 million). In addition to the two

major requests, there were 46 other ERF requests totaling $7.25 million. Other notable contributors (>$300k) were the LPS Unit 1 forced outage ($561k) and the JGS Fire protection header failure ($325k). The remaining 44 ERF requests were less than $300k each. Please see exhibit A-236 (MEW-43) for a detailed list of ERF spending.

Q. Please explain Exhibit A-197 (MEW-4), page 2.

A. Exhibit A-197 (MEW-4), page 2, illustrates the impact of inflation if the Company used inflation to forecast each O&M expense category. Column (b) presents the historical O&M expense. Column (c) presents the amount to which a hypothetical inflation rate or contract rate were applied for the test year. Column (d) presents the adjustments necessary to translate the hypothetical inflationary forecast back to the amount of Consumers Energy's actual test year forecast. Column (e) is the projected test year O&M and is the sum of columns (b), (c), and (d).

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-197 (MEW-4), page 2.

A. The historical Generation O&M expenses shown on Exhibit A-197 (MEW-4), page 2, column (b), reflect actual 12-month expenses for the period ending December 31, 2025, for Base O&M, Major Maintenance, and Environmental Operations. Column (c) applies compounded inflation to these historical amounts to reflect projected test year costs, based on annual inflation rates of 2.9% for the 12 months ending December 31, 2026, 2.5% for the 12 months ending December 31, 2027, and 0.7% for the four months ending April 30, 2028, resulting in a compounded inflation rate of 6.2%. Column (d) reflects other adjustments to O&M expenses. The projected test year O&M expense shown in column

(e) is the sum of columns (b), (c), and (d), resulting in total projected Generation O&M expense of $102.482 million for the 12 months ending April 30, 2028.

Q. Please discuss how the adjustments on Exhibit A-197 (MEW-4), page 2, column (e) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test year projected O&M expense amount of $102.482 million reflects that evaluation. Within the test year projected amount of $102.482 million, there are a number of adjustments that result in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustments that are reflected in the test year projected amount of $102.482 million.

A. As previously discussed, Karn Units 1 and 2 retired on May 31, 2023, pursuant to a Settlement Agreement in the Company's 2018 IRP. The Settlement Agreement reached in the 2021 IRP reflects the addition of Covert Units 1, 2, and 3 on June 1, 2023, and the planned retirement of Campbell Units 1, 2, and 3, in which costs are being allocated to a regulatory asset as discussed earlier in this testimony. In addition, several O&M groups have changed O&M expenses, all of which I will discuss later in this direct testimony.

Q. Please discuss the O&M expense for the Karn Units.

A. The 2025 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on May 31, 2023, leaving only Karn Units 3 and 4 operational. The projected O&M for the test year at the Karn site is $14.917 million compared to the actual O&M expense for the Karn site in 2025 of $20.274 million, a decrease of approximately 26%. A complete

discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the total O&M expense for Covert Units 1, 2, and 3.

A. The 2025 O&M expense for Covert reflects the Company's second full year of operation for Covert after taking ownership of the plant on June 1, 2023. The actual O&M expense for Covert Units 1, 2, and 3 in 2025 was $15.424 million, and the projected O&M for the test year is $14.070 million, with the biggest decrease reflected in major maintenance. The 2025 expense for major maintenance was $8.00 million, however it is projected to total $6.081 million in the test year. A complete discussion of the test year major maintenance for Covert is described later in this direct testimony. The environmental operations expense and the base O&M are relatively flat from the historic year to the test year.

Q. Please discuss the increase in total O&M expense for Ludington.

A. The projected test year total O&M expense for Ludington reflects an increase of $2.921 million from the historical year to the test year. The projected test year total O&M expense is $12.800 million as compared to the historical year total O&M expense of $9.879 million. A large portion of the increase in the projected test year total O&M expense is attributable to a $2.618 million increase in major maintenance expense. A complete discussion of the test year major maintenance for Ludington is described later in this direct testimony. The balance of the increase is reflected in the base O&M expense increase of $0.324 million.

Q. Please discuss the increase in O&M expense for the River Hydros.

A. The projected test year total O&M expense for the River Hydros reflects an increase of $2.306 million from the historical year to the test year. The projected test year total O&M

expense is $14.899 million as compared to the historical year total O&M expense of $12.593 million. Most of the increase in the projected test year total O&M expense is attributable to a $2.521 million increase in major maintenance expense. A more complete discussion of the test year major maintenance for the River Hydros is described later in this direct testimony. The base O&M expense is projected to decrease $0.213 million from $7.918 million in the historical year to $7.705 million in the projected test year.

Q. Why should the Commission approve the Company's projected River Hydro O&M expense?

A. With the divestiture of the River Hydro facilities currently pending and no Commission order expected prior to the filing of this case, the Company is seeking approval of the O&M expenses requested in this case which are needed to appropriately operate and maintain those facilities to ensure they are safe and legally compliant. Even if the divestiture is approved, the current timeline would not likely result in a completed and closed divestiture prior to the start of the test period on May 1, 2027. As such, the Company will need to continue to maintain and operate the River Hydros through a portion of the test year, at a minimum.

Further, should the divestiture not be achieved and the Company proceeds with decommissioning the River Hydros, a process that would take more than 20 years, the Company would need to continue to operate and maintain the River Hydros until the time they are decommissioned.

Q. How does the Company propose to protect customers from excessive rates if the full projected O&M expense for the test year is not required?

A. The Company requests the Commission to approve a one-way tracker for the River Hydro O&M expense. To the extent that future determinations obviate the need to reasonably and prudently spend the Company's projected test year O&M expense for the River Hydros, the Company proposes to refund the difference between the projected and actual amount of O&M expense.

Q. What does the Company mean with respect to one-way tracker?

A. The Company only intends to refund the difference between the projected River Hydro O&M expense and the actual River Hydro O&M expense in the event that actual expenses are lower than projected, it does not propose to recover additional O&M expenses should actual River Hydro O&M expense exceed the projected River Hydro O&M expense.

Q. Please discuss the increase in total O&M expense for Administration and Generation Commons.

A. The projected increase in total O&M expense for Administration and Generation Commons totals $4.234 million and is due to a number of factors including the reorganization of the Lean Organization, Enterprise Project Management tools and filling of vacancies, and operations reliability spending. While much of this funding is initially budgeted for Administration and Generation Commons, the actual O&M expense will ultimately be assigned to the individual plants at which the work is performed.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the environmental operations of the Company's AQCS. As Federal and State emissions standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation.

On a historical basis, the largest portion of this expense was incurred at the Company's Karn and Campbell coal units. However, with the 2023 retirement of Karn Units 1 and 2 and the costs of Campbell Units 1, 2, and 3 going to a regulatory asset account as of May 23, 2025, the total projected environmental operations expense has dropped significantly as I will discuss later in this direct testimony.

Q. Please explain how the projected Environmental Operations expenses for the projected test year ending April 30, 2028, was calculated.

A. Environmental Operations expenses have primarily been a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites on a historical basis. The operations component was primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. However, as reflected on Exhibit A-197 (MEW-4), page 1, line 3, columns (b) and (c), the walk from the 2025 historical expense of $5.089 million to the projected test year expense of $2.575 million reflects a cost reduction of $2.514 million despite inflationary increases. This cost reduction is a direct reflection of the costs of

Campbell Units 1, 2, and 3 being allocated to a regulatory asset as of May 23, 2025. Aside from Campbell, most of the environmental expense is associated with the continued operation of Karn Units 3 and 4 as well as projected environmental O&M expense at the gas-fired generating units, Ludington, and the River Hydros.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of the generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the Major Maintenance O&M expenses for the test year ending April 30, 2028 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

Q. Please identify the test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $33.727 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-197 (MEW-4), page 1, line 2, column (c). Test year Major Maintenance expense by generating unit is presented on Exhibit A-197 (MEW-4), page 3, column (c).

Q. Why is Consumers Energy spending $33.727 million in total Major Maintenance O&M expense during the projected test year ending April 30, 2028?

A. The Company is spending the majority of its total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy and capacity at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed and minimizing damage that could result in the event of a catastrophic failure.

Q. Are Major Maintenance expenses relatively consistent from year to year?

A. No. Although the Company attempts to plan for controlled and consistent levels of Major Maintenance, because Major Maintenance outages occur relatively infrequently, for an individual unit, it is very possible to have significant year-by-year variations in the number, duration, and magnitude of the required Major Maintenance work. Other factors such as unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

Q. Is it possible that changes to the Company's forecasted Major Maintenance plan could occur?

A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. The Company attempts to make the best decision in balancing the cost and risks associated with the operation of the equipment and attempts to minimize

the cost to customers. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability considerations can affect the actual timing of an outage and maintenance spending.

Q. Do Major Maintenance costs vary by individual generating unit(s)?

A. Yes. While the Company's natural gas generating units are similar in age, they vary in size, type, and design, so do the costs to maintain these units. As discussed earlier in this direct testimony, the Company has LTSAs for its Covert, Jackson, and Zeeland plants, with two different OEMs. Because of these differences, the LTSA payments will vary significantly from plant to plant as well as OEM to OEM.

Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch of generating units in its generation portfolio?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. What are the categories of Major Maintenance?

A. Major Maintenance is broken into two categories—outage and non-outage.

Q. Please describe what is included in the outage major maintenance O&M expense.

A. Outage major maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for HRSGs and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, LTSA inspections based upon unit operating hours, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are

needed to control the unit output. During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

Q. Please describe the work completed in a boiler inspection.

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

Q. Please describe the work completed in a turbine inspection.

A. Turbine inspections consist of disassembling, inspecting, and cleaning the different components of the turbine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Because of the extreme conditions under which these units operate, the demand for uninterrupted power, and dangers associated with operating these large pieces of equipment, industry standards recommend that inspections be completed every seven years.

Q. Please define non-outage maintenance.

A. Non-outage maintenance O&M costs typically do not require the generating unit be removed from service, but they are still critical to the operation of the unit. An example of non-outage maintenance is Mill/Pulverizer maintenance.

Campbell Site Major Maintenance

Q. Please describe Campbell Site Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, lines 1 and 2, column (c), Campbell Units 1, 2, and 3 Major Maintenance expense is forecasted to be $0.0 million in the projected test year ending April 30, 2028. This reflects that no planned major maintenance projects are scheduled for Campbell during the test year, however environmental related costs associated with the continued operation of Campbell, which were discussed earlier in this direct testimony and booked to the regulatory asset, are not reflected in Major Maintenance expense.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 8, column (c), the Covert Plant Major Maintenance expense is forecasted to be $6.081 million in the projected test year ending April 30, 2028, and includes:

- Covert Plant LTSA Major Maintenance ($2,786,805). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected premature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant Capacity Factor Used for Water and Chemicals ($1,166,667). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- RO System, operation agreement ($476,667). The scope of this project is to contract with a third party to operate and maintain the RO system;

- Covert Plant Base Outage Funding – Boiler plant equipment ($500,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- Covert SCR Cleaning Annual Maintenance ($491,728). The CGS SCR catalysts require periodic cleaning during biannual outages to restore catalytic surface area and differential pressure. Cleaning is necessary to maintain catalytic reduction of nitrogen oxides ("NO_x") and carbon monoxide ("CO") as required by the site operating permit. Cleaning is typically performed by outside contractors.

- Eight additional projects for Covert totaling $658,955 in expenses, with each individual project representing $150,000 or less in expenses. These projects include Covert Plant HEPS/FAC/Deaerator Storage Tank ("DAST") inspections, Oil Filled Transformer testing, Main Inlet Filters, replacement of CT/ST/ Boiler Feed Pump ("BFP") oil filters and Air Pre-filters, GT Exhaust Expansion Joint repairs.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 4, column (c), Karn Units 3 and 4 Major Maintenance expense is forecasted to be $1.321 million in the projected test year ending April 30, 2028, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance ($300,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;

- Karn Units 3 and 4 Major Motor Maintenance ($140,000). The plant's critical motors are significantly overdue for their required periodic maintenance, resulting in an elevated risk of equipment failure. If maintenance continues to be deferred, there is an estimated 30% likelihood of experiencing a 30-day forced outage

- Karn Units 3 and 4 Opacity Improvements ($150,000). Karn Units 3 and 4 are unable to run on oil and gas without having opacity excursions. This project will perform critical maintenance and repairs on the equipment related to these opacity issues; and

- Nine additional projects for Karn Units 3 and 4 totaling $731,000 in expenses, with each individual project representing $100,000 or less in expenses. These projects include Karn Units 3 and 4 Boiler required repairs, Karn Units 3 and 4 NERC Relay testing, Karn Units 3 and 4 Breaker maintenance, Karn Pond post-closure care, Karn Units 3 and 4 Cooling Tower Forebay cleaning.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 6, column (c), Zeeland Plant Major Maintenance expense is forecasted to be $7.318 million in the projected test year ending April 30, 2028, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract ($2,577,446). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals ($1,737,717). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Base Outage — Boiler Plant Equipment ($600,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;

- Zeeland Plant HEPS and FACS Inspections ($310,000). HEPS and FAC inspections are required to ensure safe, reliable, and compliant operation of generating units. HEPS activities include inspection and assessment of MS, hot reheat, and other high-temperature piping systems to identify creep, fatigue, and weld degradation. FAC activities focus on identifying and mitigating internal wall-thinning in FW, extraction steam, and other susceptible piping exposed to high-velocity water or steam. Execution of these programs provides significant customer value by reducing the risk of catastrophic piping failures, avoiding forced outages, and supporting reliable unit performance during peak demand periods. Proactive inspection and replacement efforts minimize safety risks to employees and the public, ensure compliance with industry and regulatory expectations, and optimize long-term asset performance. Maintaining piping integrity also improves availability, reduces derates, and avoids substantial replacement power and repair costs. These programs represent prudent, industry-standard asset management practices that support safe, reliable, and affordable service for customers;

- Zeeland Plant Excitation & Isolation Transformer Testing and maintenance. PH1 ($250,000). Zeeland's generation transformers are essential to plant reliability, and the site has no cross-ties or onsite spare units, making any failure a high-consequence event. A proactive maintenance program is required to reduce this risk and ensure continued delivery of accredited capacity. The maintenance scope includes draining and processing insulating oil, conducting internal inspections, performing planned repairs, completing electrical diagnostic testing, and developing long-term condition assessments. These activities provide accurate health evaluations, mitigate random failure risk, and allow cost-effective planning for future replacement of long-lead components. Planned transformer maintenance is significantly less costly and far more reliable than responding to an unexpected failure. Without this program, Zeeland faces a materially higher probability of outage. A transformer failure would result in an estimated 15-day forced outage, with approximately a 10% chance of occurring if maintenance is deferred. Because these transformers are single-points-of-failure, such an event directly removes the plant's accredited capacity from service. This maintenance program is a prudent investment that protects customers, preserves capacity value, and supports long-term system reliability;

- Large Oil Filled Transformer maintenance ($250,000). The scope of this project is to execute the 20-year major maintenance plan which includes (1) drain/process/reclaim oil, (2) perform internal inspections when drained, (3) perform planned repairs and evaluate as found conditions, and (4) perform electrical testing to internal circuits and supporting electrical components; and

- Eighteen additional projects totaling $1.593 million in expenses, with each individual project representing $249,990 or less in expenses. These include Water Tanks repair and coating, Phase 2 Periodic Carbon Filters replacement, Sit Stack inspections, Phase 2 Heat Exchanger cleaning, NERC Relay & DC testing compliance, and Phase 2 4160V Cable testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 7, column (c), Jackson Plant Major Maintenance expense is forecasted to be $5.587 million in the projected test year ending April 30, 2028. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals ($2,817,679). This item provides for the city water used by the Jackson Plant and for the chemicals required to operate the water purification systems that are used to

purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Switchyard SF6 Breaker 177, 277, and 500 test and inspection ($300,000). The purpose of this project is to ensure the continued safe and reliable operation of the 177, 277, and 500 SF_6 breakers, which are critical to connecting the plant's switchyard bus to the transmission grid. OEM testing and inspection—particularly measurement of internal contact life—will verify that these aging breakers can operate safely through the plant's retirement. Completing this work materially reduces the risk of catastrophic breaker failure, which could otherwise cause extensive equipment damage, force multi-week derates, create significant capacity loss exposure, trigger hazardous SF_6 cleanup requirements, and negatively affect insurance risk ratings. This project provides a cost-effective mitigation of those operational, environmental, and financial risks;

- Jackson Boiler Vent and Drain Routing ($375,800). The purpose of this project is to install a permanent steel drain line from the HRSG FW system at the Jackson Generating Station to eliminate the safety and operational risks created by the current uncontrolled drainage of hot condensate during maintenance. The new drain line will prevent hot water from spilling onto elevated walkways, ladders, operator platforms, and adjacent equipment—mitigating the risk of operator burns, slip-and-fall incidents, and potential damage to mechanical and electrical systems. This investment provides a durable and reliable solution that materially improves plant safety and reduces the likelihood of equipment failures or operational disruptions;

- Jackson LM6000 Gas Turbine Engine Repair ($400,000). These funds have been developed based on historical discovery during the Semi-Annual Borescope inspections; usually entails repairs or replacements such as normal wear items e.g. VBV work, valves, check valves or other scope. This is also used for any major discovery work; Jackson Plant LTSA — Running Maintenance Contract ($800,625). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Jackson Plant Base Outage - Boiler plant equipment ($250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and

- Eight additional projects totaling $643,121 with each individual project representing $185,000 or less in expenses. These include Jackson Turbine

Building Temp Control maintenance, Chiller Condenser cleaning, NERC Relay testing, HRSG inspections, Jackson Boiler Safety Programs HEPS and FAC inspections.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 9, column (c), LPS Major Maintenance expense is forecasted to be $5.963 million in the projected test year ending April 30, 2028, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal ($2,267,510). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;

- Trench Feature Work ($450,000). FERC Part 12 requires inspections to be performed on reservoirs every five years. This project includes performing a dam safety inspection on the upper reservoir clay liner, scour features, erosion gullies and tailrace. The annual reservoir inspection includes multi-beam sonar and side scan of the upper reservoir as well as a multi-beam sonar on the tailrace. The project is to perform engineering remediation on defects found and perform silica placement as necessary to remain compliant with FERC regulations;

- Scour Feature Repair Phase 2 and 3 ($1,047,000). The project scope includes repairing the scour features on Units 1 and 6 by placing rip rap in the areas where rip rap has been displaced by the newer and more powerful pumping units. Construction would include filling the Unit 1 and Unit 6 scour feature areas with rip rap and fill voids with concrete, and placing 2 inches of concrete between the rip rap on the entire width of the rip rap apron to a length of about 400 feet. This would lock in the rip rap throughout the entire width of the 2 feet rip rap apron and prevent the rip rap apron from being scoured away.

  The rip rap apron has experienced more scour due to the upgraded pumping units. The rip rap gets displaced, exposing the filter cloth underneath the rip rap and protecting the clay liner. Once the filter cloth is exposed, it historically has gotten ripped by the pumping units and exposed to the clay liner and potential scour. During the 2019 trench features inspection, the exposed fabric was ripped, exposing the clay liner in front of Unit 6 and allowing for the clay liner to be scoured away. The rip rap apron in front of Unit 1 has also

experienced scour, which has moved rip rap stone and exposed fabric on top of the clay liner. Since October 2019, the area of exposed clay in front of Unit 6 has grown from 6 feet diameter to 20 feet diameter and 1.5 feet of the 7 to 8 feet clay liner has scoured away.

The Company has committed to FERC that it would engineer a repair to address these recurring issues in 2020; engineering was complete in April 2020 and submitted to FERC for approval. In February 2020, the Dam Safety Surveillance Monitoring Committee ("SMC") created threshold action levels for the scour features in concurrence with the Engineer of Record for the scour feature repair. At 0-1 feet of scour of the clay liner, no actions are necessary. At 1-2 feet of scour of the clay liner, the scour feature shall be inspected in the next May or October outage. At 2-4 feet of scour of the clay liner, an emergent repair is needed;

- Nine Year Unit Mechanical Interval Inspection and Replacement ($370,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six;

- Depression Air Compressor Maintenance ($242,400). The project consists of completing the maintenance activities that require a qualified service technician to ensure the continued reliability of the four compressors that are critical to plant operation. These compressors must remain available for service at all times, and completing this work provides the necessary upkeep to sustain their performance in future years. Performing this maintenance mitigates the operational and safety risks associated with running the compressors to failure. Internal engineering analysis indicates that, without this work, there is approximately a 10% probability of a compressor failure that could result in a 15-day forced outage. This project therefore materially reduces the risk of avoidable equipment failure and supports the safe and reliable operation of the facility;

- Generator Circuit Breaker ("GCB") Pumping Pole Maintenance ($200,000). This project will fund the work scope to annually rebuild the pump poles across the site to restore their operational life as per the GCB maintenance strategy. Expected duty cycles and wear rates observed will require the site to average one pump pole set per year with an associated cost around $200k annually for the site to perform the required maintenance items to restore. This project is only for the pump poles and not the generating poles.

The GCB contact assembly is configured with both main and arcing contacts. The arcing contacts are designed to be "sacrificial" to prolong the main contact life. The GCB cannot safely operate under a fault condition once the arcing contact life is expended at 25% of life remaining, which will force the unit to be unavailable in pump mode operations until the proper maintenance is performed. The GCB pole maintenance must be addressed in a

planned outage prior to reaching 25% of calculated life remaining to mitigate costs of an individual outage just for GCB maintenance; and

- Seventeen additional projects totaling $1.386 million, with each individual project representing less than $161,000 in expenses. These include Unit 2 Penstock Intake repair, Wicket Gate repair, Oil Water Separator cleaning, Fish Entrainment Abatement Technology, and Headgate condition assessment.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 10, column (c), Hydro Major Maintenance expense is forecasted to be $6.963 million in the projected test year ending April 30, 2028, and includes:

- Hydro License Initiatives ($2,167,000). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;

- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections ($1,434,969). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years. A similar level of expense, including modest escalation, is budgeted annually from 2026 through 2029;

- Tippy Spillway Chamber Inspections and Repairs ($818,000). The project scope includes performing spillway chamber inspections, engineering for spillway chamber repairs and construction of repairs. The Tippy spillway chambers are hollow chambers underneath the spillway. In the spillway chambers, the concrete is deteriorated, rebar is exposed, and there is seepage present;

- Cooke Right and Left Upstream Wingwall replacement ($220,000). A comprehensive condition assessment and FERC Part 12D inspection of the Cooke Hydroelectric Dam were completed in 2018. These reviews identified structural deficiencies in the upstream left (north) wingwall, including cracking, spalling, and areas where reinforcement had become exposed. Underwater inspection also documented a vertical crack exhibiting evidence of sediment transport, indicating active deterioration.

The condition assessment further identified similar, though less severe, cracking and spalling in the upstream right (south) wingwall. While the right wingwall did not exhibit signs of erosion, honeycombing, or efflorescence, the degradation remains notable and requires corrective action.

As a result of these findings, the south (right) wingwall has been designated in the Company's FERC compliance obligations for repair or replacement. The north (left) wingwall presents comparable degradation and likewise requires remediation to ensure structural integrity and continued compliance with FERC dam safety requirements;

- Tippy Log Chute repairs ($340,000). Regulatory inspections identified structural deterioration of the abandoned log chute at the Tippy facility, including cracking, concrete degradation, vegetation growth, and interior damage. These conditions require corrective action to maintain structural integrity and ensure compliance with FERC dam safety requirements. The project will repair the deteriorated concrete and confirm the stability of the chute to protect the adjacent powerhouse and spillway. Completing this work prevents further degradation that could lead to regulatory non-compliance, increased repair costs, or risks to facility operations;

- River Hydro Civil Condition Assessments ($250,000). These condition assessments are required in order to maintain the health of the infrastructures at all of the Company's river hydro facilities. The assessments ensure we maintain the proper dam safety and regulatory requirements at our river hydros; and

- Nineteen additional projects totaling $1.243 million with each individual project representing $200,000 or less in expenses. These projects include River Hydro Inundation Maps & EAP, Relief Well cleaning, River Hydro Concrete repairs, Rogers Apron inspection, Croton Spillway Apron evaluation.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 12, column (c), Admin and Other Major Maintenance expense is forecasted to be $0.150 million in the projected test year ending April 30, 2028, and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance

contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (Cobb, Weadock, and Whiting units) Major Maintenance expenses for the projected test year ending April 30, 2028.

A. As shown on Exhibit A-197 (MEW-4), page 3, line 5, column (c), Classic 7 Major Maintenance expense is forecasted to be $0.218 million in the projected test year ending April 30, 2028.

Q. Why is Consumers Energy projecting to spend $0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending April 30, 2028?

A. As mentioned earlier in this direct testimony, although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. Is the Company requesting O&M recovery for the projected costs of the Campbell Retention and Separation plans?

A. No. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts through the projected test year ending April 30, 2028 are not included in the Total O&M amounts on Exhibit A-197 (MEW-4), page 1, line 6, columns (b), (c) and (d). Company witness Patton supports regulatory asset treatment of these expenses in her direct testimony and Exhibit A-174 (HLP-52).

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date.

Q. What is the purpose of the retention component of the Company's plan?

A. The Company had a strong interest in keeping qualified employees working at the Campbell site through their retirement date to ensure safe and reliable operations. Although the Company previously planned to retire Campbell on May 31, 2025, the plant has remained operational pursuant to continuing DOE Orders requiring continued operation. As a result, retaining experienced staff remains critical to maintaining safe, reliable, and compliant operations for as long as the units are required to operate. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. It was increasingly difficult to hire new employees at the Campbell site given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires provided a significant challenge to operating the three units both safely and reliably.

Q. What is the purpose of the separation component of the Company's plan?

A. After the Campbell units are retired, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of

America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Campbell retention plan?

A. The Campbell retention plan includes three benefit types: retention benefits, severance benefits, and relocation and moving benefits

Q. Please describe the retention benefits associated with the Campbell retention plan.

A. The retention benefits associated with the Campbell retention plan include three payment components: a signing incentive, periodic incentives, and a final retention incentive. The timeline for retention benefits reflects approval of the Settlement Agreement in the Company's 2021 IRP in June 2022.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in July 2022. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The

employee had to stay at Campbell until October 31, 2022 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2022, the employee forfeited the signing incentive.

Employees received a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell and rendering service for a certain period. Specifically, for service provided July 2022 through October 2022, employees received 20% of their base pay. For service provided November 2022 through October 2023, employees received 25% of their base pay. For service provided November 2023 through October 2024, employees received 30% of their base pay. The employee had to stay at Campbell until October 31 of the given year to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31 of the given year, the employee forfeited the annual incentive.

Employees received a final retention incentive equal to 60% of their base pay on or about October 31, 2025, if the employee remained at Campbell, per the previous agreement.

Because the Campbell plant remains in operation, a new retention incentive and transfer modification agreement was provided to employees. This agreement pays 12.5% of an employee's hourly wage, every 90 days, until it expires November 19, 2026.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Campbell Units 1, 2, and 3?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees who desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (seven within 60 miles of the Campbell site) to which employees can relocate, than it did in 2016. In addition, the Company also retired two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees who cannot find placement. As I previously stated, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees.

Q. Does this conclude your direct testimony?

A. Yes, it does.