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September 30, 2025

VIA ELECTRONIC CASE FILING

Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

Re: Case No. U-21870 – In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.

Dear Executive Secretary:

Enclosed for filing please find the ***Association of Businesses Advocating Tariff Equity's Direct Testimony & Exhibits of Colin T. Fitzhenry.***

A Proof of Service will be provided in a separate filing.

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

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Date: 2025.09.30 14:24:07 -04'00'

Stephen A. Campbell

SAC/lkd

cc: Parties of Record

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-21870**

Direct Testimony and Exhibits of

Colin T. Fitzhenry

On behalf of

Association of Businesses Advocating Tariff Equity

September 30, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11862

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-21870**

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STATE OF MICHIGAN
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Direct Testimony of Colin T. Fitzhenry

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from Consumers Energy

Company ("Consumers" or "Company"). They primarily take service under Consumers' Rate GPD, Rate GPTU, Rate EIP, Rate GP, Rate GSG-2 and/or Rate LTILRR.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address the Company's current electric service reliability and the Company's proposed distribution capital expenditures. Specifically, I recommend adjustments to Investment Recovery Mechanism ("IRM") capital expenditures for Low Voltage Distribution ("LVD") Pole Replacements and LVD Targeted Circuit Improvement. Additionally, I recommend adjustments to base rate capital expenditures for Overhead to Underground Conversions, Line Regulator Controller Upgrades, High Voltage Distribution ("HVD") Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation.

My silence in this testimony, or that of my colleagues in their own testimonies, with regard to any issue should not be construed as an endorsement of Consumers' position on that issue.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. The Company's claim of improving reliability is based on a "cherry-picked" view of its data, selectively focusing on a metric that excludes major weather events. A broader comparison shows that Consumers consistently ranks at the bottom among peer utilities in neighboring states, with the average Consumers customer experiencing 339 more minutes of outages per year. This poor reliability performance has occurred despite a significant increase in capital spending. From 2020 to 2024, the Company's annual distribution capital expenditures increased by 49%, or $287 million, without any meaningful reduction in customer outage minutes. To address this, the Commission should require the Company to demonstrate a clear link between its investments and quantifiable reliability improvements before approving any further rate increases.

2. I recommend adopting a 5% rejection rate for the LVD pole replacement program. This is a more realistic estimate based on utility comparisons. Using this rate would reduce capital expenses for pole replacement by 50%, resulting in an authorized IRM capital expenditure reduction of $63,750,000 in the test year and year after.

3. I recommend denying the request for additional authorized capital expenditures for vintage underground cable rejuvenation in the test year, as it does not provide immediate safety or reliability benefits and is more of a preventative maintenance project, which is not appropriate for cost recovery through the IRM. This would reduce the proposed authorized IRM capital expenditures by $45,057,250 in the test year and year after.

4. The proposed large-scale overhead to underground conversion program should be rejected entirely. The Company has not provided sufficient justification for the expansion past its pilot program, as its own data shows it is the most expensive option under the utility cost test. The Company has also shown a lack of ability to efficiently execute the program, citing significant real-world challenges with securing easements during the pilot phase. This recommendation would reduce projected test year capital expenditures by approximately $20,000,000.

5. For the line regulator controller project, I recommend reducing the proposed pace to 25% of the planned installation rate. I am concerned about the Company's benefit-cost analysis, noting it excludes key costs such as taxes, Return on Equity, interest, and potential stranded costs, which are ultimately borne by customers. The analysis also makes an unreasonable assumption that all line regulators installed before the year 2000 will fail in the next ten years, which lacks supporting evidence. This reduction would decrease projected capital expenditures for this project by $7,894,500 for the bridge period and $3,840,000 for the test year.

6. I also recommend that the Company maintain current investment levels for the HVD Lines Reliability and HVD Substations Reliability programs. The Company's recent outage data does not support a need for increased investment in the HVD system, as almost all outages over the last three years were the result of a fault in the LVD system. This would reduce projected capital expenditures: by $90,648,903 for the bridge period and $75,403,427 for the test year for the HVD Lines Reliability program; and by $39,711,365 for the bridge period and $33,964,524 for the test year for the HVD Substations Reliability program.

7. Lastly, I recommend that the $20.619 million in test year expenditures for a 138 kV dedicated customer substation be removed from the rate base because the project was canceled. Since the project was never completed and was designed for a single customer, it is not considered "used and useful." I recommend that the Company seek to recover any sunk costs from the customer who canceled the project.

My specific recommendations, which are based on the Company's historical lack of efficacy in past investment decisions result in the following reductions in the Company's proposed base rate revenue requirement and IRM expense:

- The proposed adjustments to the LVD Pole Replacements and LVD Targeted Circuit Improvement project reduce the Company's proposed authorized IRM capital expenditures by approximately $108.8 million in the test year and the year after.
    - These two adjustments reduce the Company's IRM surcharge revenue requirement in the projected test year by $5.781 million.
- Additional adjustments to Overhead for Underground Conversions, Line Regulator Controller Upgrades, HVD Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation reduce capital expenditures by approximately $138.3 million and $153.4 million for the bridge period and test year, respectively.
- These five adjustments reduce the Company's base rate revenue requirement by $22.9 million, based on the Company's requested 10.25% ROE. However, at Mr. Walters' recommended ROE of 9.5%, my adjustments would reduce the Company's claimed revenue deficiency by $22.0 million.

II. ELECTRIC SERVICE RELIABILITY

Q PLEASE BRIEFLY DESCRIBE THE COMPANY'S CURRENT ELECTRIC SERVICE RELIABILITY.

A The Company measures electric service reliability using several reliability metrics, most prominently the System Average Interruption Duration Index ("SAIDI"). Other metrics include System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Customers Experiencing Multiple Interruptions ("CEMI"). Based on the Company's data from 2015-2024, the SAIDI performance, excluding Major Event Days ("MEDs"), was 155 minutes in 2024, which was better than the projected 170 minutes.[1] According to the Company, this

[1] Kelly Direct at 29.

performance indicates that the Company's reliability investments are producing results.[2] However, in its audit report, Liberty Consulting Group assessed the Company's historical SAIDI performance and concluded that reliability had not improved over the past decade, despite increases in total capital and O&M expenditures.[3] The Company aims to improve its reliability performance and reach a SAIDI performance of approximately 128 minutes, excluding MEDs, by 2029.[4] According to Consumers, this would place the Company in the second quartile or better among peer utilities, demonstrating better than average reliability performance.[5]

Q HOW DOES THE COMPANY'S RECENT ELECTRIC SERVICE RELIABILITY METRICS COMPARE TO PEER UTILITIES?

A In the 2024 Liberty audit, it was noted that the Company's SAIDI and CAIDI metrics for 2022 and 2023 were in the 4th quartile, including MEDs, and the 3rd quartile, excluding MEDs.[6] In order to clarify the specifics of Consumers' reliability metrics within its regional context, I have prepared an analysis to include 2024 data from EIA-861, Annual Electric Power Industry Report. In my analysis, I compared the Company's SAIDI with MEDs (All Days) and SAIDI without MEDs (No MEDs) to other investor owned utilities in Michigan and states sharing a land border with Michigan (Ohio, Indiana, and Wisconsin) for the period 2020-2024. The purpose of reducing the scope of the reliability comparison analysis to only include neighboring states is so the utilities included in the analysis share a similar geographic region and are thus impacted by similar weather patterns. This data is shown in Table CTF-1 below.

[2] Kelly Direct at 25.
[3] Final Report Utility Distribution Audit of Consumers Energy, Part One, September 23, 2024, Page 71.
[4] Kelly Direct at 22.
[5] *Id.*
[6] Kelly Direct at 26.

Table CTF-1

Investor Owned Utility Historical Reliability Performance (SAIDI IEEE Standard)

			2020		2021		2022		2023		2024	
Line	Utility	State	All Days	No MEDS	All Days	No MEDS	All Days	No MEDS	All Days	No MEDS	All Days	No MEDS
1	Duke Energy Ohio Inc	OH	211.9	106.4	144.3	124.9	541.2	113.3	168.2	103.6	321.1	102.5
2	Consumers Energy Co	MI	510.3	194.7	911.2	227.9	466.6	182.0	913.0	176.4	502.6	155.0
3	Dayton Power & Light Co	OH	174.3	122.3	179.6	108.0	182.0	108.9	170.5	96.2	502.6	106.4
4	DTE Electric Company	MI	351.8	141.9	927.4	135.6	583.9	146.2	1542.3	156.8	483.0	159.2
5	AES Indiana	IN	154.7	73.4	176.4	104.4	147.3	112.5	466.8	86.7	246.9	87.3
6	Indiana Michigan Power Co	IN	300.3	154.1	426.2	148.4	389.3	120.7	155.1	94.6	156.7	97.5
7	Indiana Michigan Power Co	MI	300.3	154.1	426.2	148.4	389.3	120.7	155.1	94.6	156.7	97.5
8	Madison Gas & Electric Co	WI	27.3	22.4	39.6	31.9	110.3	22.3	64.0	23.5	278.6	41.6
9	Northern States Power Co	MI	346.0	244.0	562.2	177.0	391.1	211.8	245.2	163.5	166.3	115.5
10	Northern States Power Co	WI	346.0	244.0	562.2	177.0	391.1	211.8	245.2	163.5	166.3	115.5
11	Ohio Power Co	OH	254.6	166.8	231.0	171.4	595.3	179.4	326.1	147.6	272.2	158.1
12	Superior Water and Light Co	WI	55.7	39.6	82.3	21.4	99.6	35.7	86.1	17.0	22.4	7.2
13	The Toledo Edison Co	OH	102.8	66.8	167.0	68.6	165.6	95.4	331.4	79.9	121.0	95.4
14	Upper Peninsula Power Company	MI	292.9	206.2	273.4	148.7	566.8	204.6	425.1	140.6	404.3	186.8
15	Wisconsin Electric Power Co	WI	140.0	94.0	417.0	102.0	279.0	121.0	272.0	85.0	296.0	109.0
16	Wisconsin Public Service Corp	WI	104.0	104.0	555.0	95.0	462.0	96.0	150.0	74.0	465.0	95.0
17	Upper Michigan Energy Resources	MI	253.0	222.0	779.0	239.0	799.0	286.0	365.0	187.0	1082.0	218.0
18	Consumers Rank		17	13	16	16	12	13	16	16	15	13
19	Average w/o Consumers		213.5	135.1	371.8	125.1	380.8	136.6	323.0	107.1	321.3	112.0

Source: Form EIA-861, Annual Electric Power Industry Report, 2020-2024

As can be seen from Table CTF-1, of the 17 utilities represented, Consumers ranks between 12 and 17, depending on the metric and year, with an average rank of about 15 out of 17. This puts Consumers at or near the bottom in terms of reliability performance within its peer utilities over the last five years. In addition, the average SAIDI with MEDs for all utilities for the past five years has been approximately 322 minutes per year, but Consumers' SAIDI with MEDs average has been approximately 661 minutes per year, meaning the average Consumers' customer experienced approximately 339 minutes more of outages per year than the average customer in Michigan, Indiana, Wisconsin, and Ohio served by an Investor Owned Utility.

Q WHAT HAS BEEN THE PRIMARY CAUSE OF OUTAGES HISTORICALLY?

A I have summarized the amounts of customer minutes of power interruption ("CMI") by the outage cause for the last three years (2022-2024) in Table CTF-2 below.

Table CTF-2

Primary Cause of Outages (2022-2024)

Line	Outage Cause	Customer Minutes Interrupted	Percent of Total
1	No Specific Cause Found	188,416,635	5%
2	Unique Incident	57,626,749	1%
3	Animal	29,634,390	1%
4	Equipment Failure	358,224,514	9%
5	Trees	1,839,800,787	45%
6	Weather	1,073,280,202	26%
7	Bird	7,097,739	0%
8	Public Damage	21,484,876	1%
9	Public Tree Trimming	3,715,716	0%
10	Lightning	31,731,784	1%
11	Trees - Outside ROW	285,112,117	7%
12	Forced Outage/Emergency	21,042,345	1%
13	Car/Pole Accident	147,201,874	4%
14	Transmission/Generation	16,078,517	0%
15	Total	4,080,448,245	100%

Source: U21870-AB-CE-0700_Kelly_ATT_1.xlsx provided in response to Data Request U21870-AB-CE-0700.

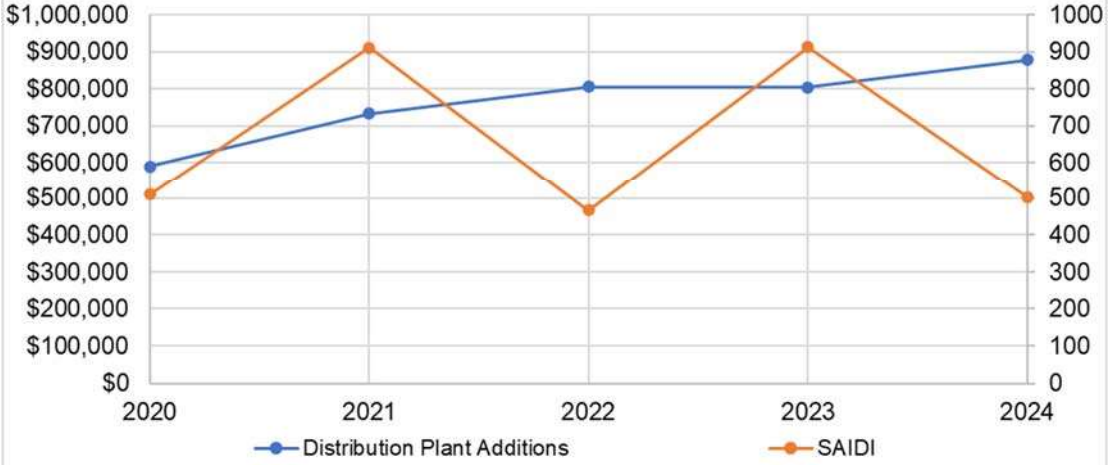
As can be seen from Table CTF-2, customers experienced over 4 billion minutes of outages over the last three years. The majority of outages were the result of trees or trees outside the ROW (52%) and the second leading cause of outages was the result of weather (26%). Meaning that only 22% of outages were the result of other causes such as equipment failures, car/pole accidents, unique incidents, etc. If the Company intends on making any meaningful improvement to its future reliability metrics, then the primary focus should be on vegetation management as opposed to asset replacement since equipment failures only account for a small percentage of total outage minutes.

Q HAS THE COMPANY BEEN ACCELERATING INVESTMENT IN ITS DISTRIBUTION SYSTEM OVER THE PAST FIVE YEARS?

A Yes. I have shown the distribution plant additions and the Company's SAIDI with MEDs over the period 2020-2024 in Figure CTF-1.

Figure CTF-1

Distribution Plant Addditions and SAIDI
($1,000s)



Source: Downloaded from S&P Market Intelligence, FERC Form 1 Template, 9/23/25.

As can be seen from Figure CTF-1, the Company's distribution plant additions, or capital expenditures, have increased from approximately $590 million in 2020 to $878 million in 2024, an increase of $287 million or 49% in five years. Meanwhile, there has been no discernable trend in the Company's SAIDI with MEDs metric over the same period. This means that the Company has not been able to reduce customer outage minutes, despite significant increases in the annual distribution capital expenditure levels.

In addition, the Company's investment in its distribution system has had a significant impact on its overall rate base. Consumers' requested rate base of $15.4 billion in this proceeding is $3.7 billion more than the rate base approved in Docket No. U-20697 ($11.7 billion) for the 2021 test year. An increase in a utility's rate base,

usually from investments in new infrastructure, is a primary driver of the utility's revenue requirement, which directly results in higher rates for customers.

Q WHAT CAN YOU CONCLUDE FROM THIS ANALYSIS?

A The facts presented demonstrate a troubling pattern of increasing investment with no corresponding improvement in reliability for customers. The Company's position that its reliability is improving is based on a cherry-picked view of its data, selectively focusing on SAIDI excluding MEDs, while ignoring the more critical all-weather SAIDI metric that reflects the actual experiences of its customers. While the Company claims its SAIDI performance without MEDs is improving, a broader comparison shows that it consistently ranks at the bottom of its peers. The average Consumers customer experiences an unacceptable 339 minutes more of outages per year than the average customer of other electric utilities both within Michigan and in neighboring states.

This poor performance is occurring despite a massive influx of capital. The Company's distribution plant additions have increased by 49%—or $287 million—over the past five years. This increase in spending has not translated into any meaningful reliability gains for customers. The Company should be directing its investment to focus on the primary cause of outages, as opposed to focusing on capital investments to grow future returns.

The Commission must view this request for further investment with extreme skepticism. Continuing to grant these requests based on the Company's current flawed methodology would be a disservice to customers, forcing them to bear the cost of millions of dollars in new investment, while receiving little tangible benefits in return. Instead of approving more funding, the Commission should demand that the Company first demonstrate a clear link between its investments and quantifiable improvements

in reliability before any further rate increases are considered. My recommendations in this proceeding to reduce the Company's proposed distribution capital investments consider the historical lack of efficacy the Company has demonstrated in prior investment decisions.

III. LOW VOLTAGE DISTRIBUTION LINES RELIABILITY

Q PLEASE DESCRIBE THE COMPANY'S LVD LINES RELIABILITY SUBPROGRAM.

A The LVD Lines Reliability Subprogram is a capital program designed to ensure safe and reliable operation of Consumers' LVD lines. It is part of the broader strategy outlined in the Company's Reliability Roadmap, which aims to improve electric service and enhance the grid's resilience against severe weather. The program includes various projects aimed at addressing specific concerns on the LVD system. The LVD Lines Reliability subprogram consists of five investment categories: (1) targeted circuit improvements; (2) pole replacements; (3) ATR loops; (4) circuit exit enhancements; and (5) ROW and easement acquisition.[7] The Company is proposing that cost related to the two largest investment categories, targeted circuit improvements and pole replacements, be recovered through the Company's IRM. The targeted circuit improvements and pole replacements investment categories will be discussed in greater detail later on in my testimony.

[7] Partlan Direct at 44.

Q WHAT ARE THE PROJECTED COSTS FOR THE LVD LINES RELIABILITY SUBPROGRAM?

A The projected capital expenditures for the LVD Lines Reliability Subprogram are $180,763,000 for the 16-month bridge period ending April 30, 2026[8] and $312,886,000 for the 12-month test year ending April 30, 2027.[9] However, the majority of the LVD Lines Reliability Subprogram capital expenditures, $276,191,000 in the test year, are being proposed for recovery through the IRM surcharge.[10]

Q WHAT WAS THE COMMISSION'S DECISION REGARDING THIS PROGRAM IN THE LAST RATE CASE FINAL ORDER (DOCKET NO. U-21585)?

A In the Final Order for Docket No. U-21585, the Commission did not approve all of the Company's proposed expenditures, but it did authorize the Company to move forward with certain investments. The Commission authorized $86.347 million for Year 2 of IRM, which included $68.523 million for the LVD Lines Reliability category.[11]

The Commission adopted the ALJ's recommendation to disallow specific project expenditures within the LVD Lines Reliability category. For the Zonal Health Improvements and Right-of-Way ("ROW") acquisitions, the Commission agreed with the ALJ that the Company's evidence was insufficient. The Commission found that Consumers failed to provide historical cost data for the relabeled "Zonal Health" program and did not adequately justify the significant spending increase.[12] Similarly, for ROW acquisitions, the Commission found that the Company lacked the necessary detail linking projected costs to specific projects.[13] The Commission also agreed with

[8] A-166 (JMP-1), Page 14 of 37.
[9] A-167 (JMP-2), Page 10 of 28.
[10] Kelly Direct at 102, Figure 31, Proposed IRM Expenditures.
[11] U-21585 Order at 365.
[12] U-21585 Order at 62.
[13] U-21585 Order at 64.

the Attorney General's disallowance for secondary conversions, finding that the significant ramp-up in spending was not sufficiently supported with details on the benefits to a relatively small number of customers.[14]

The Commission explicitly stated that future requests for cost recovery in this category must be supported by more complete historical data and a clear justification of how the investments deliver value to customers.[15] Additional details regarding the Commission's decision in U-21585 are discussed in my colleague's testimony, ABATE witness Jim Dauphinais.

IIIA. LVD Pole Replacements

Q PLEASE DESCRIBE THE COMPANY'S PLAN FOR LVD POLE REPLACEMENTS.

A The Company's plan for LVD pole replacements is to address poles identified as needing replacement through inspections.[16] A new program will conduct groundline inspections on all poles on a 12-year cycle, aiming to inspect 125,000 poles each year.[17] Based on the age and condition of the poles, approximately 10% are expected to be classified as "rejected" and will be replaced.[18] According to the Company, this proactive replacement strategy is considered more economical and safer than waiting for poles to fail. The new standard for LVD primary poles is Class 3, which can withstand wind gusts up to 141 MPH without ice or 71 MPH with half an inch of ice.[19] Poles range from Classes 1-6, with lower class poles being able to withstand harsher conditions. The Company has also started a pilot to install ductile iron poles in certain

[14] *Id.*
[15] U-21585 Order at 63.
[16] Partlan Direct at 19.
[17] Partlan Direct at 60.
[18] Partlan Direct at 61.
[19] Partlan Direct at 63.

locations as a more durable alternative to wood poles.[20] The Company plans to ramp up LVD pole replacements from 2,300 in 2025 to 12,500 in 2027, which will cost $127,500,000 in the test year period.[21]

Q DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S LVD POLE REPLACEMENT PLAN.

A Yes. The Company has said that it "generally agrees" with Liberty's recommendation to place less emphasis on asset age when deciding whether to replace assets.[22] However, when determining the forecasted rejection rate for pole replacements, the Company solely relied on asset age. The Company assumes that (i) all poles with a vintage between 1937-1960 are considered high risk and will have a greater than 15% rejection rate, (ii) poles with a vintage between 1961-1980 are considered moderate risk poles and have a 10%-15% rejection rate, and (iii) poles with a vintage between 1981-2025 are considered minor risk and have less than a 10% rejection rate.[23] By using these assumed rejection rates by pole vintage and then weighting those values based on the average age of the population of distribution poles, the Company arrived at the estimated 10% rejection rate for all poles.

Q HOW SHOULD THE COMPANY FORECAST THE REJECTION RATE FOR POLES?

A The Company should rely on a sample of pole inspections to make a more accurate determination of the appropriate rejection rate. Using a sample of pole inspections is the most practical way to estimate the overall rejection rate of a much larger population

[20] *Id.*
[21] A-167 (JMP-2), Page 6 of 28.
[22] Kelly Direct at 22.
[23] Exhibit No. A-129 (MPG-19), page 69.

of poles. A properly selected sample allows for a reliable assessment of the entire population.

Q ABSENT THIS INFORMATION, WHAT IS YOUR RECOMMENDATION?

A I recommend the Company adopt a 5% rejection rate when estimating the number of pole replacements during groundline inspections. This is at the higher end of rejection rates when comparing the actual rejection rates of utilities who have utilized groundline inspections for pole replacement. For example, the rejection rate of Midwest Energy was 4.63% during the first cycle through its distribution system.[24] Reducing the rejection rate to 5% reduces the Company's proposed capital expense for pole replacement by 50%. This adjustment reduces the Company's proposed authorized IRM capital expenditures by $63,750,000 in both the test year period and the year after.

IIIB. LVD Targeted Circuit Improvement

Q PLEASE DESCRIBE THE COMPANY'S PLAN FOR LVD TARGETED CIRCUIT IMPROVEMENT.

A The Company's LVD targeted circuit improvement plan includes several project types within four distinct project categories including: (1) reducing the amount of non-standard voltage on the distribution system; (2) zonal health investments; (3) converting open-wire secondary to multiplex; and (4) rejuvenating vintage underground cable. The proposed test year expenditures for each of these projects include $33,115,000 for voltage conversion, $14,224,000 for zonal health, $14,670,000 for

[24] https://www.mwenergy.com/news/view/pole-inspections-minimize-storm-damage-bring-improved-reliability

secondary conductors, and $65,989,000 for underground cable for a combined $127,998,000 in the LVD Targeted Circuit Improvement category.[25]

Q DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S TARGETED CIRCUIT IMPROVEMENT PLAN?

A Yes. As stated by the Commission, the purpose of the IRM is to address "safety and reliability." [26] However, the vintage underground cable rejuvenation project does not provide immediate safety or reliability benefits. Since this involves the replacement of cable that is already located underground, the safety and reliability benefits of undergrounding have already been realized by the Company. Thus, this project is more accurately characterized as preventative maintenance, which would only provide future benefits in the event that an existing underground cable fails. This raises concerns that the Company's plan is not using the IRM as the Commission intended.

Q HAS THE COMPANY FORECASTED THE SAFETY AND RELIABILITY BENEFITS OF REJUVENATING VINTAGE UNDERGROUND CABLE?

A No. The Company did not quantify the benefits of rejuvenating vintage underground cable, despite requesting an additional $38,080,000 in capital expenditures in the test year above amounts included in the bridge period.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S LVD TARGETED CIRCUIT IMPROVEMENT?

A I recommend the Commission deny the Company's request for additional capital expense for vintage underground cable rejuvenation in the test year period. Since the

[25] A-167 (JMP-2), Multiple Pages.
[26] Case No. U-21389 Final Order at 273.

bridge period is 16 months, the average monthly capital expenditures would be $1,744,312. Applying the monthly capital expenditures to the 12-month test year period would result in an annual expense of $20,931,750. This adjustment reduces the Company's proposed authorized IRM capital expenditures by $45,057,250 in both the test year period and the year after.

IV. OVERHEAD TO UNDERGROUND CONVERSIONS

Q PLEASE DESCRIBE THE COMPANY'S OVERHEAD TO UNDERGROUND INVESTMENT PLAN.

A The Company's Overhead to Underground conversion program is an investment category aimed at improving the grid's resiliency and mitigating wildfire risks.[27] This initiative involves replacing sections of existing overhead lines with underground lines and their associated equipment. The program, which was initially introduced through a pilot project, is planned to ramp up to 400 miles of undergrounding annually, with a goal of starting projects in the test year and reaching full, annual capacity by 2028.[28] Research from other utilities indicates that undergrounding can improve a circuit's performance by 90% or more, by removing its exposure to trees and severe weather events.[29] The cost of this work is estimated to be comparable to other methods of hardening the grid, such as installing aerial spacer cable or tree wire.[30] While the Liberty audit recommended delaying the plan, the Company has decided to move forward with the program based on the positive results of the pilot, which demonstrated the cost-effectiveness and reliability benefits of undergrounding.[31] The Company is

[27] Exhibit No. A-132 (MPK-22) at 27.
[28] Kelly Direct at 67.
[29] Partlan Direct at 105.
[30] Kelly Direct at 62.
[31] Kelly at 23.

proposing $1.25 million in bridge period capital expenses for Overhead to Underground Conversions and $20 million in the test year.

Q WHY DID LIBERTY RECOMMEND DELAYING IMPLEMENTATION OF THE OVERHEAD TO UNDERGROUND CONVERSION PROGRAM IN ITS AUDIT?

A Liberty recommended delaying the expansion of Consumers' overhead to underground conversion program beyond the initial pilot phase because, at the time of the audit, there were currently not enough grounds to support a full-scale expansion of the program, with Liberty citing significant uncertainties about the actual costs and reliability benefits. [32] The report suggested that the major expansion in annual expenditures should be delayed by at least a year or more and could potentially be reduced, based on the lessons learned from the pilot projects.[33] The report notes that, historically, undergrounding has been much more expensive than overhead construction, and that, while it's a good resiliency measure in specific areas, like those with high tropical storm or wildfire exposure, it's not clear it will be beneficial at the levels identified in the Electric Distribution Infrastructure Investment Plan.[34] The report also questions whether the reliability improvements from undergrounding are significantly better than those from less costly alternatives, such as accelerated tree trimming.[35]

[32] Final Report Utility Distribution Audit of Consumers Energy, Part Two, September 23, 2024, Page 70.
[33] *Id.*
[34] *Id.*
[35] Final Report Utility Distribution Audit of Consumers Energy, Part Two, September 23, 2024, Page 71.

Q HAS THE COMPANY PRESENTED INFORMATION ON THE COST- EFFECTIVENESS OF THE UNDERGROUNDING PILOT PROGRAM?

A Yes. Company Witness Michael Kelly discusses the Present Value of the Revenue Requirement ("PVRR") for the undergrounding pilot projects in his direct testimony. According to the Company's own data and using the Utility Cost Test ("UCT"), undergrounding is the most expensive option when compared to Aerial Spacer Cable including Forestry, Tree Wire Including Forestry, and Existing Overhead Including Forestry using the utility cost test ("UCT").[36] However, the Company also provides the results of a Societal Cost Test ("SCT"), which demonstrates that Undergrounding is the least cost option.[37] The SCT uses a lower discount rate than the UCT, which assigns more value to benefits further out in the investment lifecycle, when the benefits are more speculative.

While I have concerns about the methodology deployed by the Company in both the UCT and SCT, the Company has not demonstrated that Undergrounding is consistently the preferred solution using both cost tests.

Q DO YOU HAVE ANY ADDITIONAL CONCERNS ABOUT THE COMPANY'S PROPOSED UNDERGROUNDING PROGRAM?

A Yes. The Company has acknowledged that the Undergrounding Pilot was not completed as planned due to challenges with securing easements on four of the undergrounding projects that were originally approved in Case No. U-21389. The four projects are as follows:[38]

- Blue Star-Pier Cove LCP 622: A group of landowners in this area opposed the project as designed, requiring significant design changes and leading the Company to defer the project beyond the period covered by Case No.

[36] Kelly Direct at 62, Figure 24.
[37] Kelly Direct at 62, Figure 25.
[38] Response to Data Request U21870-AB-CE-0702.

U-21389. All easements have since been acquired for this project to move forward.

- Dean Road-Hogan LCP 951: Multiple landowners had concerns with the initially proposed alignment for this project, but the Company has redesigned the project to use the road right of way instead. All easements have since been acquired for this project to move forward.

- Peck Road/M-91 LCP 473: This is an unusually complex project in terms of the number of easements required, and the Company's easement acquisition process has taken longer than expected. The design for this project took longer than expected, which delayed starting easement acquisition.

- Merson-Merson LCP 412: This project involved landowners requesting a number of changes, such as working around septic systems and drain fields. The Company anticipates acquiring these remaining easements in September 2025.

The Company is proposing to scale the size of the undergrounding program from 8.8 miles completed in the Pilot to 400 miles in this proceeding. Since the Company is already having issues completing specific circuits identified for undergrounding, then I expect that problems will only be exacerbated when the program is increased by 45 times its current size. In addition, if the Company changes its proposed projects from one circuit to another due to issues with landowners, the benefits of undergrounding in the alternate circuit may not be as great as the benefits in the originally identified circuit. This would further reduce the cost-effectiveness of the program and lower the benefits shown in the Company's UCT and SCT.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED UNDERGROUNDING PROGRAM?

A The Company's proposed large-scale overhead to underground conversion program should be rejected. While the concept of undergrounding has potential, the Company has not provided sufficient justification to move forward with a full-scale expansion at this time. The Company's own data, as presented in its cost-effectiveness analysis,

shows that undergrounding is the most expensive option under the UCT. The reliance on the societal cost test to justify the program is speculative, as it places a high value on long-term, uncertain benefits.

Furthermore, the Company's own experience with the initial pilot program demonstrates significant real-world challenges. The issues encountered in securing easements, which led to project delays and redesigns, highlight a major logistical hurdle. This lack of demonstrated ability to efficiently execute the program, coupled with the uncertainty of cost and benefits, makes the current proposal imprudent.

The Commission should follow the recommendation of the Liberty audit and require the Company to complete and thoroughly analyze the initial pilot projects before committing to a massive capital expenditure. This will allow for a more accurate assessment of actual costs and benefits and will ensure that any future expansion is based on sound data and a proven ability to execute, rather than on unsubstantiated projections. The Company has a responsibility to demonstrate a clear link between its investments and tangible improvements for customers before being granted further rate increases for this program. This recommendation would reduce the Company's test year capital expenditures by $20 million.

V. LINE REGULATOR CONTROLLER PROJECT

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED LINE REGULATOR CONTROLLER PROJECT.

A The Company's proposed Voltage Regulator Controller project aims to upgrade all controllers on its voltage regulators, integrating dynamic remote-control and monitoring capabilities into the electric distribution system. This initiative is part of the broader Distribution Circuit Modernization efforts, which focuses on deploying technologies to

improve grid reliability and resiliency. The project is designed to enhance power quality, enabling customers to receive energy within tariff-specified limits. This not only ensures regulatory compliance, but also allows customer equipment to operate more efficiently. By supporting Conservation Voltage Reduction and Volt-VAR Optimization, the new controllers can reduce energy consumption and peak demand.

Beyond these benefits, the project also provides cost-saving and safety advantages. The two-way communication capability allows for proactive maintenance and replacement of equipment before it fails, which helps prevent customer outages and avoids the higher costs of emergent repairs. The ability to remotely monitor and operate these devices also reduces the need for field crews to perform manual inspections, improving the safety of electric line workers by limiting their exposure to electrical and traffic hazards.

The Company plans to upgrade 220 regulator locations in 2025 and 217 locations in 2026, which is projected to be the final year of the mass deployment. After this, the communicating regulator controller will become the standard installation for new or replacement locations. The projected capital expenditures for this project are $10,526,000 for the bridge period and $5,120,000 for the test year. A Benefit Cost Analysis ("BCA") for this project is provided in Exhibit A-146 (SAM-5).

Q WHAT WERE THE RESULTS OF THE COMPANY'S BCA SUPPORTING THE LINE REGULATOR CONTROLLER PROJECT?

A The Company forecasts that the line regulator controller project will produce $23,606,493 of benefits and cost $15,129,138, which results in net benefits of $8,477,355.[39] In addition, the Company forecasts that the project will yield 56,625

[39] Exhibit A-146 (SAM-5).

minutes of avoided CMI, which have not been monetized and included in the above results of the BCA.[40]

Q DO YOU HAVE ANY CONCERNS WITH THE METHODOLOGY DEPLOYED BY THE COMPANY TO CONDUCT THE BCA?

A Yes. The Company's DCF model treats the initial investment as a negative cash flow and future benefits as positive cash flows, which are then discounted to their Net Present Value ("NPV"). However, this model fails to include several key costs, such as taxes, Return on Equity ("ROE"), interest, and stranded costs. In a regulated monopoly, taxes and an ROE are collected from ratepayers through the Company's revenue requirements after the investment is put into service. By excluding them from the BCA, the Company underestimates the true financial burden on customers. The model does not factor in the interest paid on debt used to finance the project. This is another cost ultimately borne by ratepayers that is not reflected in the analysis. The BCA does not account for the possibility of stranded costs. If an asset is replaced before the end of its depreciable life, customers are forced to pay for both the original, now-retired asset and its replacement. This double payment represents a significant financial risk to ratepayers that the Company's analysis ignores.

By not including these additional costs, the Company's BCA presents a misleading picture of the project's cost-effectiveness. The reported net benefits appear artificially high because they are not offset by the full spectrum of costs customers will ultimately pay. In a regulated environment, where consumers bear the full cost of any approved investments, the decision-making process should prioritize rate affordability. If the analysis were to properly include taxes, ROE, interest expense, and potential

[40] *Id.*

stranded costs, the project's true costs would be significantly higher. This more accurate assessment would likely demonstrate that the project is less cost-effective than the Company claims. Ultimately, the Company's current BCA modeling approach is inappropriate for making investment decisions that directly impact customer rates.

Q ARE THE INPUT ASSUMPTIONS UTILIZED BY THE COMPANY IN THE LINE REGULATOR CONTROLLER BCA REASONABLE?

A No. A majority of the monetized benefits, $12,880,000, are calculated based on the assumption that current line regulators installed prior to 2000 will *all fail* over the next ten years. However, the Company has not provided any analysis to support this assumption. Excluding the forecasted benefit of future line regulator failures would reduce the NPV of benefits to $10,726,493, which is $4,402,645 less than the cash value of the project. Alternatively, if only 273 of the line regulators installed prior to 2000 would fail, then the project's net benefits would be negative, and the project would no longer be forecasted to be cost-effective.

Q GIVEN THE ISSUES IDENTIFIED IN THE COMPANY'S LINE REGULATOR CONTROLLER BCA, WHAT IS YOUR RECOMMENDATION?

A I recommend that the Company reduce the proposed pace of the line regulator controller project to 25% of the proposed installation rate. As a result, the Company's plans to upgrade 220 regulator locations in 2025 and 217 locations in 2026, should be reduced to 55 regulator location in 2025 and 54 locations in 2026. This would allow the Company to utilize actual historical data to validate and improve the input assumptions used in the line regulator controller BCA model, which the Company could provide in its next rate case. I recommend that the capital expense be reduced by a

corresponding 25% of the proposed expense for the line regulator controller project to reflect the reduction in installation rate. This would reduce the Company's projected capital expenditures for this project by $7,894,500 for the bridge period and $3,840,000 for the test year.

VI. HIGH VOLTAGE DISTRIBUTION CAPITAL EXPENDITURES

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED HVD CAPITAL EXPENDITURES.

A The HVD system consists of HVD lines, HVD and LVD substations, and a protective relay system. It operates at 46 kV or 138 kV. The Company has 4,600 miles of overhead HVD lines and 23 miles of underground HVD lines. The HVD system also includes 1,138 substations, with 144 HVD, 830 LVD, and 164 Strategic Electric Customer substations. Consumers Energy is proposing significant capital expenditures for the HVD system in its filing. In the bridge period, the Company is projecting HVD system expenditures of $542,846,000, and for the test year, the projected expenditures are $417,546,000. These investments are intended to improve reliability and resiliency, and to serve new customers.

Q DID THE LIBERTY AUDIT INCLUDE RECOMMENDATIONS REGARDING THE COMPANY'S HVD RELIABILITY INVESTMENTS?

A Yes. Liberty did not find substantial need or benefit to increase investment in HVD lines or in substations, given the fact that most SAIDI minutes, and most projected SAIDI improvements, are related to the LVD system.[41]

[41] Kelly Direct at 24.

Q DOES THE COMPANY'S RECENT OUTAGE DATA CONFIRM THAT MOST OF THE OUTAGE MINUTES ARE ATTRIBUTABLE TO THE LVD SYSTEM?

A Yes. None of the outages reported in Table CTF-2 occurred at a fault location with a voltage level exceeding 24.9 kV. Furthermore, Transmission/Generation outages accounted for only 0.4% of the total CMI. Thus, almost the entirety of outages over the last three years (2022-2024) were the result of a fault that occurred in the LVD System. As a result, recent outage data does not suggest a need to make investments to improve the reliability of the HVD system.

Q ARE ANY OF THE HVD SYSTEM CAPITAL EXPENDITURES BEING PROPOSED PRIMARILY TO SUPPORT HVD SYSTEM RELIABILITY?

A Yes. The proposed investments are broken down into several subprograms and categories. The HVD Lines Reliability and HVD Substations Reliability subprograms are being proposed to improve reliability in the HVD system.

The HVD Lines Reliability program includes projected expenditures of $133,667,000 in the bridge period and $107,667,000 in the test year and will address deteriorated HVD line assets through line rebuilds, pole top rehabilitation, pole replacements, switch replacements, line sensor deployments, and right-of-way acquisition.

The HVD Substations Reliability program includes projected expenditures of $47,322,000 in the bridge period and $39,680,000 in the test year. These funds are for circuit breaker and switcher replacements, transformer bushing replacements, switch replacements, and other targeted equipment replacements.

Q BASED ON THE RECENT HVD SYSTEM RELIABILITY, WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE HVD LINES RELIABILITY AND HVD SUBSTATION RELIABILITY PROGRAMS?

A I recommend that the Company reduce capital expenditures to match the 2024 levels for the HVD reliability programs. The 2024 capital expenditure levels were the following:

- $32,263,573 for the HVD Lines Reliability program.
- $5,715,476 for the HVD Substations Reliability program.

Implementing this recommendation would result in the following capital expenditure reductions from the Company's proposed amounts:

- HVD Lines Reliability program:
  - Bridge period reduction of $90,648,903.
  - Test year reduction of $75,403,427.
- HVD Substations Reliability program:
  - Bridge period reduction of $39,711,365.
  - Test year reduction of $33,964,524.

VII. 138 KV DEDICATED CUSTOMER SUBSTATION

Q PLEASE DESCRIBE THE 138 KV CUSTOMER SUBSTATION.

A The 138 kV substation was being constructed for a dedicated customer in west Michigan.[42] The Company had included $20.619 million in the test year for this new substation, but as of July 2025, this project was cancelled, and the Company is in the process of cancelling the work orders.[43]

[42] Attachment 142, Page 1 of 313.
[43] Response to Data Request U21870-AB-CE-0695.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE 138 KV DEDICATED SUBSTATION.

A I recommend the $20.619 million be removed from the test year rate base. This project was never completed, and since it was designed for a single dedicated customer, the project is not considered used and useful. Therefore it would be imprudent to include this expenditure in the test year. I also recommend that the Company seek to recover any sunk costs from the customer who canceled the project. This could be done through a deposit or another mechanism specified in the original agreement with the customer.

VIII. CONCLUSION

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A I recommend that the Commission view the Company's request for further capital investment with skepticism due to a pattern of increased spending without a corresponding improvement in reliability. The Company's claim of improving reliability is based on a selective view of its data, and a broader comparison with peer utilities shows that Consumers consistently ranks near the bottom. The Company's capital expenditures have increased by 49% over the past five years, but this has not resulted in meaningful reliability gains for customers.

I recommend that instead of approving more funding for research and investments that have only calculated savings of customer outage minutes without regard to full program costs and benefits,[44] the Commission should demand the

[44] Some of the proposed investments appear to be for research with only expectations of reductions in customer outages, incomplete system-wide costs, and no benefit cost analyses. For example, the Metro Modernization project objective is stated to provide technology options for upgrading its vaults by evaluating sensors, assessing switching equipment, developing communications, and investigating remote-controls (McPhail Direct at 40). Further, this project does not have an estimate of

Company demonstrate a clear link between its investments and actual quantifiable and/or benchmarked improvements in reliability before any further rate increases are considered. In total I have proposed seven recommendations, two of which, LVD Pole Replacements and LVD Targeted Circuit Improvement, reduce the Company's proposed IRM capital expenditures. I have shown the impact of these adjustments on the Company's proposed IRM expense in Table CTF-3 below.

TABLE CTF-3

Summary of ABATE Adjustments to Company Proposed IRM
($ 1,0000s)

Line	Description	Test Year	Year After
1	LVD Pole Replacements	$ (63,750)	$ (63,750)
2	LVD Targeted Circuit Improvement	(45,057)	(45,057)
3	Total	$ (108,807)	$ (108,807)
4	Estimated Revenue Requirement Impact at **Company** ROE	$ (5,781)	
5	Estimated Revenue Requirement Impact at **ABATE** ROE	$ (5,570)	

As can be seen from Table CTF-3, my proposed adjustments to the LVD Pole Replacements and LVD Targeted Circuit Improvement project reduce the Company's proposed authorized IRM capital expenditures by approximately $108.8 million in the test year and the year after. This lowers Consumers' projected test year IRM surcharge revenue deficiency by $5.781 million based on the Company's proposed ROE of 10.25% and common equity ratio of 50.75%. However, at Mr. Walters' recommended ROE of 9.5% and 50% common equity ratio, it would lower Consumers' projected test year IRM surcharge revenue deficiency by $5.570 million.

system-wide deployment costs nor a benefit cost analysis (Response to data Request U21870-AB-CE-0715).

Also, the Peer-to-Peer Automation Scheme project has a proposed initial investment of $1.165M without a determination of costs for system-wide deployment and without a benefit cost analysis (Response to data Request U21870-AB-CE-0714).

The remaining five recommendations I have proposed impact the Company's base rate revenue requirement in the test year. These include adjustments to Overhead to Underground Conversions, Line Regulator Controller, HVD Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation. I have shown the impact of these adjustments in Table CTF-4 below.

TABLE CTF-4

Summary of ABATE Adjustments to
Company Proposed Capital Expenditures and Revenue Requirement
($ 1,0000s)

Line	Description	Bridge Period	Test Year
1	Overhead to Underground Conversions	$ -	$ (20,000)
2	Line Regulatory Controller	(7,895)	(3,840)
3	HVD Lines Reliability	(90,649)	(75,403)
4	HVD Substations Reliability	(39,711)	(33,965)
5	138 kV Dedicated Customer Substation	-	(20,619)
6	Total	$ (138,255)	$ (153,827)
7	Estimated Revenue Requirement Impact at **Company** ROE		$ (22,866)
8	Estimated Revenue Requirement Impact at **ABATE** ROE		$ (22,030)

As shown in Table CTF-4, if the Commission adopts my recommendations, the Company's capital expenditures would be reduced by approximately $138.3 million and $153.4 million for the bridge period and test year, respectively. In total, I recommend a minimum reduction of $22.9 million to Consumers' claimed revenue deficiency, based on the Company's requested 10.25% ROE. However, at Mr. Walters' recommended ROE of 9.5%, my adjustments would reduce the Company's claimed revenue deficiency by $22.0 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Colin T. Fitzhenry

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I received a Bachelor of Science in General Engineering from the University of Illinois Urbana-Champaign, which provided a broad background in mechanics and control systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I was involved with generation operation at both Vermilion Power Station and Tilton Power Station.

Since joining BAI in January 2013, I have provided assistance in several regulated utility matters. Some of these include resource planning, transmission planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers, electrical and commodity price forecasting, and power procurement.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, finance, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm have participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

545937

Question:

Request 27:

Referring to Attachment 142 at page 1, line 1:

a. Please provide all workpapers that support the $20.619 million of test year spending for this new 138kV dedicated substation.
b. Please provide a detailed narrative explaining the status of this project, including investment made to date.
c. Is this project included in the $14.1 billion of distribution plant in service shown in WPEAD-67?
d. Please explain if the customer to be served by this new substation is included in the test year billing determinants used for rate design.

Response:

a. See Attachment 1 to this response. This attachment also contains supporting information regarding the project being inquired about in discovery request 21870-AB-CE-0696.
b. This project was just recently cancelled in July of 2025. The Company is in the process of cancelling the work orders. The cancellation activities, including evaluating equipment and other work completed for salvage/re-purpose, and removing charges from the work orders and sub-program is ongoing with the intention that those investments will be netted out in the future via salvage/re-purpose of equipment and/or transfer to O&M expense. Through August 2025, $10,170,475 has been spent on this project since its inception.
c. This project is partially included in distribution plant in service ($14.1B) and distribution CWIP.
d. No, this customer/project was not included in the test year billing determinants used for rate design.

Witness: Megan L. Hayward
Date: September 22, 2025

Question:

Request 32:

For the past three years (2022-2024) please provide the following data for each outage:

a. Outage Cause (wildlife, equipment failure, weather related, etc.);

b. Outage Location;

c. Voltage Level at Location of Fault;

d. Outage Duration; and

e. Number of Customers Impact.

Response:

Please refer to Attachment 1 to this response for the requested data. The information on the first tab is excluding Major Event Days, while the information on the second tab is including Major Event Days.

Witness: Michael P. Kelly
Date: September 22, 2025

CONSUMERS ENERGY COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

Response of: Consumers Energy Company to the Second Set of Data Requests of Requesting Party: Association of Businesses Advocating Tariff Equity

The Attachment

U21870-AB-CE-0700_Kelly_ATT_1.xlsx

HAS BEEN EXCLUDED FROM THIS EXHIBIT DUE TO LENGTH / SIZE CONSTRAINTS

Question:

Request 34:

Please refer to the Direct Testimony of Michael Kelly, pages 60-65, and provide the following information regarding the Company's proposed undergrounding.

a. On page 60, Mr. Kelly states that the Company "was not able to convert some of these circuits to underground during the test year due to an inability to secure easements." Please provide further information as to why the Company was unable to secure easements, along with documents and information regarding any disputes with property owners.

b. For the undergrounding projects approved in Case No. U-21389, provide the number of avoided outages and customers impacted as a result of the undergrounding that has been realized since the projects went in-service. Explain how this compares to the Company's projections of avoided outages or reliability improvements.

c. At each location where the Company is proposing to perform 50 miles of undergrounding, provide the following information for the past five years (2020-2024):

1. Number of outages; and

2. Outage cause.

Response:

a. The Company had challenges with easements on four of the undergrounding projects that were originally approved in Case No. U-21389, as follows:
    - Blue Star-Pier Cove LCP 622: A group of landowners in this area opposed the project as designed, requiring significant design changes and leading the Company to defer the project beyond the period covered by Case No. U-21389. All easements have since been acquired for this project to move forward.
    - Dean Road-Hogan LCP 951: Multiple landowners had concerns with the initially proposed alignment for this project, but the Company has redesigned the project to use the road right of way instead. All easements have since been acquired for this project to move forward.
    - Peck Road/M-91 LCP 473: This is an unusually complex project in terms of the number of easements required, and the Company's easement acquisition process has taken longer than expected. The design for this project took longer than expected which delayed starting easement acquisition.
    - Merson-Merson LCP 412: This project involved landowners requesting a number of changes, such as working around septic systems and drain fields. The Company anticipates acquiring these remaining easements in September 2025.

b. Since the undergrounding projects approved in Case No. U-21389 have gone into service, none of the undergrounded portions have experienced any unplanned outages. Please also refer to discovery response 21870-ST-CE-0205. In my direct testimony in Case No. U-21389, in which the

underground pilot was proposed, I stated that the Company expected to see reliability improvements of 90% or better[1]. The realized reliability improvements to date are effectively 100%.

c. Please refer to Attachment 1 to this response.

Witness: Michael P. Kelly
Date: September 22, 2025

[1] Refer to page 38, line 3, of my direct testimony in Case No. U-21389.

Question:

Request 46:

Referring to the Direct Testimony of Scott McPhail. Regarding the Peer-to-Peer Automation Scheme Project:

a. Please identify the specific vendor and explain what this investment consists of (i.e., software/equipment and the names and specifications of such software/equipment). Please also provide the evaluation criteria for vendor selection.

b. As the proposed investment of $1.165M is only for the initial implementation of this technology of one initial scheme, what does the Company expect that it will spend on this technology for system wide implementation?

c. Please provide information to prove that this technology has been adopted by other utilities with proven success in minimizing outage impacts by optimally automatically restoring customers.

d. For the assumed 200 CAIDI average duration value within the SAIDI benefit per regular ATR loop of Exhibit SAM-7, please document how the value of 200 was derived and why that is appropriate.

e. What is the benefit cost ratio of the proposed initial investment, and what is the benefit cost ratio for the full investment at scale across the system?

Response:

a) At this stage of the project, two vendors have been chosen for continued simulation testing in a lab environment: G&W LaZer and Eaton FAM. Both automation solutions will utilize the existing specification for ATRs (the G&W Viper with SEL 651R controller) as the devices to execute the physical switching as is done today with ATR Loops. These vendors were chosen via a formal request for proposal event and the evaluation team used the following criteria categories during their ranking exercise: Meets core functionality requirements, model/software robustness flexibility maintenance and ability to modify schemes, operational performance and programming, maintenance and engineering functions, IT/OT functionality and support, and previous experience or references provided.

b) Once fully operational, the Company plans to incorporate this technology into the existing ATR program discussed by Company Witness Partlin. This is a natural evolution to more complex loops schemes as opposed to the one-to-one loop schemes completed today under the ATR program. Future ATR funding is anticipated to be used to support a system-wide deployment. The Company has not determined at this time what a system-wide deployment cost would be. Once testing is completed between the two vendors mentioned in part (a), a more definite cost estimate for system wide deployment would be available.

c) Alabama Power has implemented the use of peer-to-peer communication feeders in their service territory, and National Grid is known to have utilized the technology as well. This

information was secured through SME attendance at industry conferences and benchmarking conversations with the peer utilities.

d) Using a CAIDI (average duration of all system outages) of 200 minutes derived from CAIDI excluding MEDs reported to the MPSC. The Company took the average of the last 5 years, which equals 191, and estimated up to 200 CAIDI as this was assumed to be a conservative estimate of what outage duration might be encountered into the future. If the 5-year average of 191 CAIDI were used in the analysis, the avoided CMI benefit would drop by 4% resulting in 176,426,318 mins versus the 184,739,600 shown in Exhibit A-148.

e) Investments in the electric grid are not solely made for economic reasons but to improve service to customers through better reliability. A reduced Customer Minute Interruption (CMI) was calculated in the analysis as Exhibit A-148 (SAM-7) resulting in improved reliability for customers as opposed to a benefit cost ratio.

Witness: Scott A. Mcphail
Date: September 22, 2025

Question:

Request 47:

Referring to the Direct Testimony of Scott McPhail. Regarding the Metro Modernization project:

a. Outside of this project please explain how and how often Metro vaults are routinely inspected to assess their switching and communication equipment for potential repairs or replacement in meeting Company standards.

b. Does the Company routinely investigate and evaluate new technologies, such as underground sensors, remote switching capability, and communications among Company equipment? If not, please explain why not.

c. As this project will target one to two vaults to upgrade initially at a cost of $955k, what is the expected benefit cost ratio of this initial cost? Also, what is the expected benefit cost ratio of the full system-wide deployment of these technologies?

Response:

a. Maintenance of the metro system is explained in Figure 78 of Exhibit A-129 (MPK-19). There is currently no communicating equipment in metro vaults.

b. Yes. Grid Automation is the department in which new and advanced use cases involving increased sensing, data monitoring, and control capabilities are considered. The intent of the Metro Modernization project is to evaluate new technologies, such as underground sensors, remote switching capability, and communications. This overall initiative will determine which technologies meet the needs of the Company and integrate them into future designs.

c. Investments in the electric grid are not made solely for economic reasons but to improve service to customers through better reliability and in this case, reduce exposure of co-workers resulting in safer operations. The Company has not performed the requested cost benefit analysis. The Company has provided both the reduction in Customer Minute Interruption (CMI) which results in improved reliability for customers, as shown in Exhibit A-151 (SAM-10), and the reduction in safety risks for co-workers.

Witness: Scott A. Mcphail
Date: September 22, 2025