October 29, 2025

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

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

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find:

- **Revised Testimony of Consumers Energy Company's witnesses Stacy H. Baker (Direct - Redacted) , Patrick D. Daly (Rebuttal), Jeffrey A. Myrom (Direct), Jennifer M. Partlan (Direct), Andrew R. Snider (Direct), and Sara E. Stewart (Direct);**
- **Revised Public Exhibits A-208 (PDD-63), A-213 (PDD-68), A-214 (PDD-69), A-216 (PDD-71), A-217 (PDD-72), A-169 (JMP-4), and A-170 (SES-1); and**
- **Exhibit A-230 (JAM-6).**

Revised Confidential Exhibits A-23 (SHB-8) and A-26 (SHB-11) on behalf of Company witness Stacy H. Baker are being filed under seal with the Michigan Public Service Commission and will be available to all parties that have signed NDAs via the shared OneDrive folder.

This is a paperless filing and is therefore being filed only in a PDF. Also included is a Proof of Service showing electronic service upon the persons included in Attachment 1.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2025.10.29 16:22:11 -04'00'

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

cc: Parties per Attachment 1 to the Proof of Service.

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

REDACTED

REVISED DIRECT TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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 organizational change management. This includes the management of the IT long-term financial plan, administration of portfolio management, cloud financial 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; and
- Case No. U-21806 – 2024 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;
- Changes in the functions of the IT Department;
- 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 Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6);
- 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;

- 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 Asset Refresh projects and the Application Currency projects;

- Individual IT project synopses with a supporting, detailed exhibit (Exhibit A-24 (SHB-9) for Enhancement projects, along with a detailed worklist of the enhancement work backlog found in Exhibit A-25 (SHB-10);

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

- Further information about and justification of several larger and more complex projects for which projected spending varies from amounts forecasted in Case No. U-21585, including the following projects:

  - Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM"),

  - ARP-Printer Asset Management ("PAM"),

  - ARP-Workstation Asset Management ("WAM"), and

  - SAP High-performance ANalytic Appliance ("HANA") Database Migration;

- 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, ARP-InfoBlox, and ARP-OT Electric, consolidating them into the following new ARP projects:

  - ARP-Network-Common; and

  - ARP-Network-Electric;

- Further information on the actual costs for projects which had disallowances in Case No. U-21585:

- IT Operations Management – Service Operations,
- Operational Technology – Service Management Upgrade,
- Software Asset – Service Management Upgrade, and
- SolarWinds Performance Monitoring Expansion Upgrade; and

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

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 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;
Exhibit A-18 (SHB-2)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2024 - 13-month balance ending December 31, 2024, and for the projected years 2026 – 13-month balance ending April 30, 2027;
Exhibit A-19 (SHB-3)	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;

Exhibit A-12 (SHB-4)	Schedule B-5.1	Projected Capital Expenditures Information Technology Summary of Actual and Projected Electric and Common Capital Expenditures;
Confidential 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 2024, 2025, 2026, and 2027;
Confidential Exhibit A-21 (SHB-6)		Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects;
Exhibit A-22 (SHB-7)		Asset Refresh Programs Projected Electric and Common Capital Expenditures, For the Projected Year 2026 and Test Year Ending April 30, 2027, and For the Historical and Projected Years 2024 and 2025;
Confidential Exhibit A-23 (SHB-8)		Application Currency Programs Projected Electric and Common Capital and O&M Expenditures for the Years 2026, 2027, and Test Year 12 Months Ending April 30, 2027;
Exhibit A-24 (SHB-9)		Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis;

Exhibit A-25 (SHB-10)	Enhancement Worklist Detail for Years 2016 through October 21, 2024; and
Confidential Exhibit A-26 (SHB-11)	Projected 13-Month Average of IT S/4HANA Cloud Implementation Costs for the projected years 2026 – 13-month balance ending April 30, 2027.

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 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. Have there been any changes to the IT functions that are new in Case No. U-21870?

A. Yes. The following changes have been integrated in my direct testimony and exhibits: (1) the Security Department is part of the IT Department and no longer represented by a separate witness; (2) the Company has integrated the analytics function (Analytics and Outreach) that was part of the Customer Interactions function into the IT Department; and (3) the Company has also integrated the analytics function that was a part of the Process, Analytics & Technology function, within Operations Performance, into the IT Department. These changes, new in Case No. U-21870, better centralize the Company's technology expenditures and expenses.

The Security Department capital expenditures and O&M expenses will continue to be represented as a separate business category in testimony and exhibits, while the Analytics expenses and expenditures will be represented in the IT business category for IT Operations O&M expense and the appropriate business category for capital expenditures and IT Investments O&M expense.

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 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 by accelerating the Company's exit from coal-fired generation 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 transaction 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

[1] Available at https://www.sophos.com/en-us/content/state-of-ransomware.

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.

While cyber security is no longer a new area, each year impacts from cyber security incidents increase. According to a 2024 Sophos report on the state of ransomware, while the rate of ransomware attacks dropped slightly since 2023, the average payout more than doubled from $1,500,000 in 2023 to $3,900,000 in 2024. In addition to ransomware, the Company must protect against data breaches and threats to critical infrastructure, cognizant of the North American Electric Reliability Corporation's ("NERC") ballooning Critical Infrastructure Protection ("CIP") compliance fine maximums and the federal government's warning regarding potential critical infrastructure attacks from Russia or China as part of global geo-political tensions. In this environment, it is more important than ever that utility security teams are prepared with plans that address the need for securing customer data, maintaining compliance, protecting customer privacy, and protecting the critical infrastructure that serves the Company's 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" extorsion 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 signals 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.

As for the Trump Administration, it 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 are the immediate beneficiaries of sound local decisions and investments designed to address risks, including cyber attacks, wildfires, hurricanes, and space

weather."[3] 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 year, 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.

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

[3] 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/.

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 increase 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 Company has new NERC/CIP requirements for electric systems. While gas focused, the TSA (Transportation Security Administration) security directives also affect the Company's corporate systems, which are a part of this case.

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 does 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.

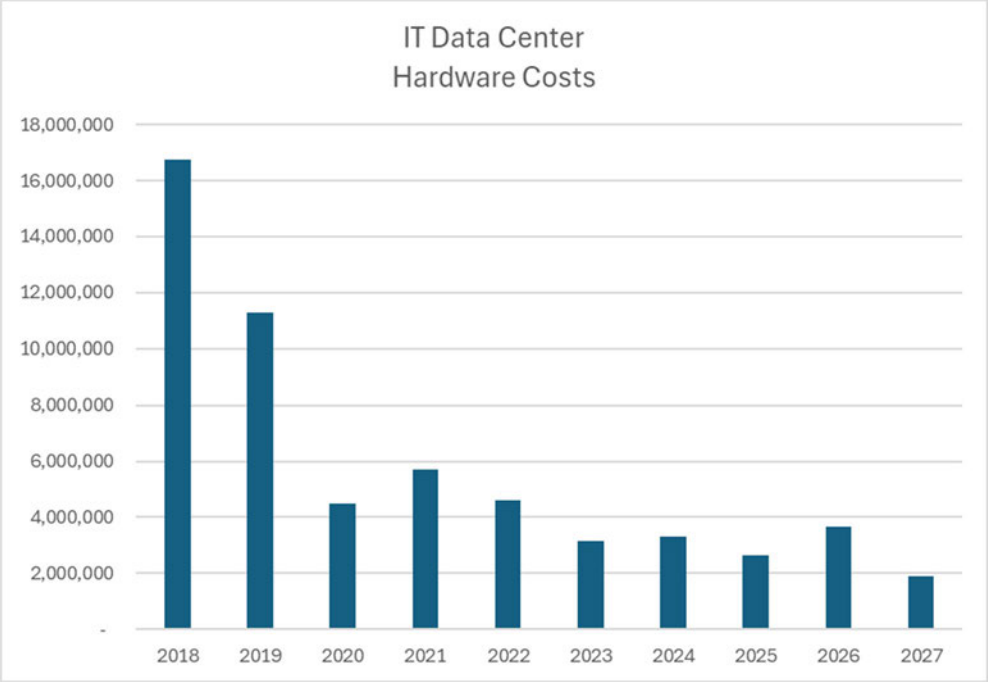
Q. Is the Company migrating to the cloud and what are the advantages of leveraging increased cloud capabilities?

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 electricity 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 Years 2024, 2025, 2026, and 12 months ending April 30, 2027. 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 2024 historical IT Operations O&M expense as $51,403,000;

- Column (c) identifies the total 2025 projected IT Operations O&M expense as $58,460,000;
- Column (d) identifies the total 2026 projected IT Operations O&M expense as $66,327,000;
- Column (e) identifies the total projected IT Operations O&M expense for the 4 months ending April 30, 2027 as $22,441,000;
- Column (f) identifies the total projected IT Operations O&M expense for the Test Year as $66,659,000; and
- "Labor" line items include employee labor; "Contracts" line items include hardware and software licenses and maintenance, and software subscriptions; "Material" line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; and "Contractor" line items include staff augmentation, the Company's managed services contracts, and other contracted services. "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) provides the historical amount that an inflation rate was applied to;
- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year IT Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments in Exhibit A-17 (SHB-1), page 2, column (i).

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 contract 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 2025, as reflected in Exhibit A-17 (SHB-1).

A. The IT Operations O&M expense in 2025 of $58,460,000 is projected to be an increase over 2024, which is $47,095,000 for IT and $11,365,000 for Security. The reason for the increase in 2025 is the result of organizational changes and the necessity to fund continued investment in programs to sustain and improve system reliability; to maintain, improve, and secure critical enterprise systems that support the Company's IRP and EDIIP; and to prevent obsolescence and risk to business operations offset by cost-saving measures. Key drivers for the change from 2024 to 2025 for IT include: (1) net labor increased based on merit increases ($0.19 million) – transfer of website from Customer Operations and analytics resources from Customer Interactions and Operations Performance ($0.56 million) to IT, increase in resources supporting grid and electric asset management ($0.33 million), backfill of resources supporting analytics ($0.5 million), and offset by move of network resources to Security ($0.2 million); (2) increase material costs ($0.65 million); (3) increase in contractor ($1.3 million), which a portion ($0.12 million) is based on the transfer of website contractors costs from Customer Interactions; (4) net increase in contracts for cloud subscriptions and license and maintenance agreements due to cost

optimization efforts offset by annual increases ($2.1 million); and (5) a decrease in Non-Labor Other ($0.58 million) based on reduction in business expenses.

Key drivers for the change from 2024 to 2025 for Security include: (1) labor increased based on merit increases ($0.08 million) and increase for resources to support the Fusion Center and move of network resources from IT to Security ($0.71 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($1.2 million) including reductions in MS Azure costs offset by an increase in cloud security platform; (3) increase in contractor ($0.59 million) based on reduction in Physical Security contractors; and (4) decrease in Non-Labor Other ($0.5 million) based on reduction in business expenses.

Q. Please describe the projected IT Department IT Operations O&M expense for 2026, as reflected in Exhibit A-17 (SHB-1).

A. The IT Operations O&M expense in 2026 of $66,327,000 is projected to be an increase over 2025, which is $54,964,000 for IT and $11,362,000 for Security. The reason the Company is projecting an increase in 2026 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 include: (1) net labor increase due to merit increase ($0.23 million) offset by resource efficiencies; and (2) increase in cloud subscriptions and license and maintenance agreements ($7.9 million) including costs related to the Genesys Cloud Migration, Standard Work Plan, and Digital-Hybrid Cloud and Data Center Migration projects and additional increases offset by cost optimization efforts to keep costs flat.

Key drivers for the change from 2025 to 2026 for Security include: (1) net labor increase based on merit increases ($0.09 million) offset by resource efficiencies; and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

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 IT Operations O&M expense in the test year of $66,659,000 is projected to be an increase over 2026, which is $55,297,000 for IT and $11,362,000 for Security. 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 include: (1) labor is flat due to merit increase ($0.08 million) offset by resource efficiencies; and (2) increase in cloud subscriptions and license and maintenance agreements ($0.34 million), including costs related to the Digital-Hybrid Cloud and Data Center Migration projects.

Key drivers for the change from 2026 to the test year for Security include: (1) labor increase based on merit increases ($0.03million) offset by resource efficiencies, and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset 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 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 ending December 31, 2024 and the

projected 13 months ending April 30, 2027. 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. This working capital adjustment is provided by Company witness Patrick D. Daly on Exhibit A-12 (PDD-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 Years 2024, 2025, 2026, and the 12 months ending April 30, 2027. Page 1 provides a summary of the gas 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 2024 historical IT Investments O&M expense as $8,536,000;
- Column (c) identifies the 2025 projected IT Investments O&M expense as $13,174,000;
- Column (d) identifies the 2026 projected IT Investments O&M expense as $26,169,000;
- Column (e) identifies the 4 months ending April 30, 2027 projected IT Investments O&M expense as $8,857,000;

- Column (f) identifies the Test Year projected IT Investments O&M expense as $26,303,000;

- For Investments Planning expense, "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and

- For Investments expense, "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 Costs" line items include staff augmentation, managed services, and other contracted services; "Non-Labor Overhead" line items include overheads; and "Non-Labor Others" line items include pension expense, administrative/general expense, Allowance for Funds Used During Construction ("AFUDC"), 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) provides the historical amount that an inflation rate was applied to;

- Columns (d), (f), and (h) provide the inflation increases for each respective period;

- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;

- Column (i) includes amounts that were projected using other methods; and

- Column (j) provides the projected test year IT Investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments indicated in Exhibit A-19 (SHB-3), page 2.

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $362,000 for IT and $4,000 for Security 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 IRP, EDIIP, and other Company long-term plans. Inflation is also not used to project future IT Investments O&M expense. The other adjustments for IT Investments O&M expense of $17,317,000 for IT and $816,000 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 Confidential Exhibit A-20 (SHB-5).

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 and make necessary and prudent capital expenditures to achieve the outcomes of the IRP, 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-5.1.

A. Exhibit A-12 (SHB-4), Schedule B-5.1, 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 2024 historical year capital expenditures as $44,023,000;
  - Column (c) identifies the 12 months ending December 31, 2025 projected bridge year capital expenditures as $52,118,000;
  - Column (d) identifies the 4 months ending April 30, 2026 projected bridge year capital expenditures as $28,191,000;
  - Column (e) identifies the 16 months ending April 30, 2026 projected bridge year capital expenditures as $80,310,000; and
  - Column (f) identifies the 12 months ending April 30, 2027 projected test year capital expenditures of $77,719,000.
- Page 2 of 2
  - Column (b) identifies the 4 months ending April 30, 2025 capital expenditures as $14,378,000;
  - Column (c) identifies the 12 months ending April 30, 2026 capital expenditures as $65,931,000;
  - Column (d) identifies the 12 months ending April 30, 2027 projected bridge year capital expenditures as $77,719,000; and
  - Column (e) identifies the 28 months ending April 30, 2027 projected bridge year capital expenditures as $147,360,000.
- 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 Others" line items include pension expense, administrative/general expense, AFUDC, and business expenses.

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

A. Confidential 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 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 the difference between Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5).

A. Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5) are both 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-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and
- Confidential Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2024, 2025, 2026, and 2027.

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

A. Confidential Exhibit A-21 (SHB-6) 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 Confidential Exhibit A-20 (SHB-5). Confidential Exhibit A-20 (SHB-5) 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:
  - Project Name is the name of the project that indicates the project objective;
  - 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 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 Confidential Exhibit A-21 (SHB-6). 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 Confidential Exhibit A-20 (SHB-5). Additionally, the ROM Adjusted Test Year Capital is identified for each project later in my testimony.

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2024	$44,022,631	$44,022,631
2025	$56,793,609	$52,118,163
2026	$99,164,570	$84,574,240
2027	$73,477,399	$64,007,880
Test Year	$90,602,180	$77,718,786

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, MPSC Staff ("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. Confidential Exhibit A-20 (SHB-5) 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. Confidential Exhibit A-21 (SHB-6) 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 Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6). 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
Electric Geographic Information System (GIS) Design Platform Modernization	$1,476,532	$1,181,225	$136,794	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Catastrophic Crewing (CatCrew) Version 2.0	$351,467	$281,173	$57,067	A.Snider	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Electric GIS Utility Network Transformation	$1,324,225	$1,059,380	$519,952	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Integrated Energy Management Platform Optimization	$1,343,299	$1,074,639	$507,797	M. Metz	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Service Restoration Artificial Intelligence	$825,723	$94,746	$660,578	A.Snider	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1

Additionally, the Application Currency-Electric-O&M and Capital, Application Currency-Electric & Gas Shared-O&M and Capital, 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. 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 Jessica R. Byrom:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M	Exhibit References
Customer Order Service Tracker	$735,345	$588,276	$154,745	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1
Multi-Account Online Account Management	$893,008	$714,406	$185,073	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1

Additionally, the Application Currency-Customer-O&M and Capital and Product Family Enhancements-Customer-O&M and Capital will be discussed later in my 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
2025 Union Contract Changes	$0	$0	$99,515	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Enterprise Risk Management	$0	$0	$47,135	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Self Service Vendor Portal	$61,629	$49,303	$77,930	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1

Additionally, the Application Currency-Corporate-O&M and Capital 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[4]

[4] https://www.michigan.gov/dtmb/-/media/Project/Websites/dtmb/Law-and-Policies/Legislative-Reports/FY2023/Sec-829-Report-of-PA-166---IT-Lifecycle-2023.pdf?rev=7b90fd55a9104194aa50e978d570bfec&hash=1A969DADCAF5A71CD5F0746D0DEE08A4

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

A. Exhibit A-22 (SHB-7) 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-22 (SHB-7).

A. Each page of Exhibit A-22 (SHB-7) 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 $1,153,267 in capital and $140,683 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.
  - **Problem Statement:** When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

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

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

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

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project differ from the $576,228 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of $1,022,838 (Confidential Exhibit A-20 (SHB-5), column (n), line 217) are $446,610 more than the $576,228 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 309).

The difference is due to the call recording system's hardware being end of life and there is risk of failure. Secondly, there is a need to refresh an additional auditorium to improve collaboration capabilities.

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

A. Beginning in 2025, the ARP-Cyber Security project is being 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.

- The **ARP-Cyber-Common** project requires $843,849 in capital and $11,215 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.
  - **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 hardware lifecycle; and (2) performing application upgrades.
  - **Alternatives** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresch cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.
- The **ARP-Cyber-Electric** project requires $430,291 in capital and $17,616 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.
  - **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 hardware lifecycle; and (2) performing application upgrades.

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

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

A. Beginning in 2025, the ARP-Core Network, ARP-Local Area Network, and ARP-Infoblox 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.

- The **ARP-Network-Common** project requires $549,198 in capital and $11,177 in O&M in the test year.

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

  - **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; or (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.

- The **ARP-Network-Electric** project requires $51,630 in capital and $916 in O&M in the test year.

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

  - **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; or (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.

- The **ARP-OT Support Electric** project requires $1,084,783 in capital and $20,142 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 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.

- The **ARP-OT Support Common** project requires $42,643 in capital and $1,062 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 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 included: (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 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.

- The **ARP-Physical Security** project requires $1,449,104 in capital and $7,826 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 considerations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and

incidents. If the Company does not maintain these assets, it could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

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

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

- **Alternatives:** Alternatives considered include: (1) not refreshing physical security assets; and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

Q. Please explain the ARP-PAM project.

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

- The **PAM** project requires $237,618 in capital and $3,099 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. This does not mean that all printers are replaced after five years – merely that printers are assessed on a five-year cycle for possible replacement.

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

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-PAM project differ from the $501,862 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of $1,013,149 (Confidential Exhibit A-20 (SHB-5), column (n), line 147) are $511,287 more than the $501,862 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 253).

Q. Please explain why the Company's 2025 projected electric allocation capital expenditures for material costs for ARP-PAM differ from the previous case.

A. The Company's 2025 projected electric allocation capital expenditures for material costs of $1,013,149 differ for ARP-PAM from the materials projections in the previous case due to the deferral of refreshes of devices from 2020 – 2023. The refreshes were deferred due to resources working remotely due to the pandemic.

Q. Please explain the ARP-FDAM project.

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

- The **ARP-FDAM** project requires $4,850,461 in capital and $3,099 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 before they fail; and (2) allowing field workers to complete their job tasks.
    - **Scope:** The project scope consists of replacing field device assets according to the four-year refresh cycle.
    - **Alternatives:** Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.

Q. How are the annual projected costs 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 $1 million annually.
    - The Company reviews actual historical new purchase costs for the past four years to ensure the $1 million is reasonable and prudent;
  - 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-22 (SHB-7).

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-22 (SHB-7), page 5, 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
2024 Actual	662	• Field device replacements based on refresh schedule. • 84 field device replacements moved from ARP-WAM to ARP-FDAM.
2025 Plan	480	• Field device replacements based on refresh schedules. • 415 fewer refreshes than planned due to retirement of all G1 version devices, downsizing Marshall training room needs and reduced gas construction needs.

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.

New Purchases

Year	Field Device	Reason for variance
2024 Actual	149	Field devices based on actual new employee/contractors.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project differ from the $3,387,972 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-FDAM project of $2,172,954 (Confidential Exhibit A-20 (SHB-5), line 144, column (n)) is $1,215,019 less than the $3,387,972 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 252).

The following describes the reason for the difference:

1. Field device replacements decreased $1.20 million due to fewer refreshes than planned based on retirement of all G1 version devices, downsizing Marshall training room needs, and reduced gas construction needs; and

2. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-FDAM project differ from the $2,948,011 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-FDAM project of $5,136,183 (Confidential Exhibit A-20 (SHB-5), line 218,

column (n)) is $2,188,172 more than the $2,948,011 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 310).

The following describes the reason for the difference:

1. Field device replacements increased by $0.72 million due to 215 field devices moved from ARP-WAM to ARP-FDAM;

2. Field device replacements increased by $0.29 million due to 88 field devices that were initially purchased for training in 2022;

3. Field device replacements increased by $1.13 million due to 337 field devices that were initially purchased as a part of an Electric and Gas Operations effort in 2022;

4. Field device replacements increased by $0.02 million due to an increase in unit cost for CF55 field devices; and

5. Labor and Non-Labor Other increased by $0.03 million to support the increase in number of field device replacements.

Q. Please explain the ARP-Radio project.

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

- The **ARP-Radio** project requires $1,029,710 in capital and $133,351 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, and consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters.

- **Alternatives:** The alternatives considered 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 $323,576 in capital and $24,131 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 purchase extended maintenance, move some of these assets to the cloud with the Digital - Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.

Q. Please explain the ARP-WAM project.

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

- The **ARP-WAM** project requires $4,395,889 in capital and $39,776 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 costs 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 million annually.
    - The Company reviews actual historical new purchase costs for the past four years to ensure the $1 million is reasonable and prudent;
  - 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-22 (SHB-7).

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 2025, 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-22 (SHB-7), page 15, 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
2024 Actual	1,839	0	• 138 fewer PC devices replaced due to reduction in resources and reduction of shared PC devices, such as kiosks and lab devices. • 233 Desktop replacements deferred to 2025 due to resource availability. • No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2025 Plan	2,968	0	• 233 Desktop replacements deferred from 2024 due to resource availability. • 218 PC devices that are not planned to be replaced due to reduction in resources. • No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2026 Plan	2,196	0	• No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2027 Plan	2,159	4,318	• Monitor replacements based on an eight-year replacement cycle.

New Purchases

Year	PC Device	Monitor	Reason for variance
2024 Actual	323	331	Based on actual new employee/contractor volume.

Q. Do the Company's 2024 actual electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $4,260,099 projected in Case No. U-21585?

A. Yes. The 2024 actual electric allocation capital expenditures for material costs for the ARP-WAM project of $3,993,657 (Confidential Exhibit A-20 (SHB-5), column (n), line 56) are $266,442 less than the $4,260,099 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 177).

The following describes the difference:

1. Desktop replacements decreased by $0.81 million due to fewer requests for desktops, reduction in resources and shared devices, and deferral of desktop replacements to 2025, as discussed above;

2. Laptop replacements increased by $0.64 million due to more requests for these devices;

3. Accessories decreased by $0.07 million; and

4. New PC purchases decreased by $0.03 million based on actual hiring.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $5,896,927 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-WAM project of $5,646,692 (Confidential Exhibit A-20 (SHB-5), column (n), line 148) are $250,235 less than the $5,896,927 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 255).

The following describes the difference:

1. Desktop replacements increased $0.39 million due to deferral of replacements from 2024 to 2025, as discussed above;

2. Laptop and tablet replacements decreased by $0.40 million based on reductions in resources;

3. Accessories decreased by $0.38 million due to decrease in laptop and tablet replacements, as described above; and

4. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the $4,609,542 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project of $4,013,510 (Confidential Exhibit A-20 (SHB-5), column (n), line 221) are $596,032 less than the $4,609,542 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 313).

The following describes the difference:

1. Laptop and tablet replacements increased by $0.25 million based planned replacements;

2. Monitors decreased by $0.86 million, as they were inadvertently planned for 2026 and should not have been planned until 2027, per eight-year refresh cycle for monitors.;

3. Accessories decreased by $0.02 million due to decrease in monitors, as described above; and

4. New purchases electric allocation decreased by $0.01 million based on current electric allocation factors that are updated annually.

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 $65,865 in O&M in the test year.
  - **Description:** The project will upgrade the Company's 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 solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.
  - **Alternatives:** Alternatives considered include: (1) evaluating other software options. This option would 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 would introduce costly technical and financial risks. (3) upgrading 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 2025-2026** project requires $27,444 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 solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer version.

  - **Alternatives:** Alternatives considered include: (1) evaluateing 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) evaluating other software options. This option would

introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.(3) upgrading to the newest version of the current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2027-2028** project requires $115,263 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 solutions with market leaders; and (2) upgrading the vendor software from the current version to a newer version.
  - **Alternatives:** Alternatives considered include: (1) evaluating SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) evaluating other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) moving to cloud option. This option would be expensive and has an unclear timeline.

(4) waiting until a future upgrade cycle. This option introduces technical risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **AxWay Secure Transport 2027 Upgrade** project requires $76,842 in O&M in the test year.

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

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

  - **Objectives:** The value this project brings the Company, its customers and business partners by: (1) addressing known problems and limitations of the current software platforms; (2) ensuring continued secure, scalable, and critical data transmission services running through Axway; (3) creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste; And (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 **Critical Substation Upgrade** project requires $3,498,167 in capital ($3,135,966 ROM Adjusted Capital) and $396,667 in O&M in the test year.

  - **Description:** This project will implement enhanced security measures at the Company's most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity and increase the reliability of electric delivery to 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 substations, increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow it 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. These activities will be performed

at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onekama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run).

- **Alternatives:** Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the sites. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time. (2) The best option is implementing enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.

- The **HR Support Pack and Business Software Inc ("BSI") Upgrade 2026 and 2027** projects require the following O&M in the test year.

Project Year	Test Year O&M
2026	$246,223
2027	$123,112

- **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:** Alternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll.(2) there is no economical cloud solution, so this option was not entertained(3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

- The High Voltage Distribution **("HVD") SCADA Upgrade** project requires $335,461 in capital ($268,369 ROM Adjusted Capital) and $163,773 in O&M in the test year.

  - **Description:** The Electric HVD Monitoring System Upgrade project upgrades the software and hardware components of the HVD SCADA system. This system is used to monitor and control generation, transmission, and HVD voltage circuits. The upgrade will provide new functionality and enable new capabilities.

  - **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

as staying current with the solution provider upgrades is critical to the resiliency of both systems.

- **Scope:** The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying application hardware; (3) implementing new functionality for improved value to the Company; (4) making necessary configuration changes; and (5) updating documentation related to the integration changes.

- **Alternatives:** Alternative considered include: (1) deferring 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 the 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 third-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) doing nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) The option chosen is to complete the upgrade with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.

- The **Itron Enterprise Edition ("IEE") 2025 Upgrade** project requires $50,812 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; and (2) migrating the database to the next version required by the application.

- **Alternatives:** Alternatives considered include: (1) defering the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's Meter Data Management ("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 **Itron Enterprise Edition 2027 Upgrade** project requires $83,541 in capital ($66,833 ROM Adjusted Capital) and $102,784 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 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; (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) defering 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 **ISIS Papyrus 2026 Upgrade** project requires $328,999 in capital ($263,199 ROM Adjusted Capital) and $114,044 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 that customers retain unfettered access to their paper bills, dunning notices, and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity, and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards.

  - **Objectives:** The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

  - **Scope:** The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

  - **Alternatives:** Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.

- The **Rate Change Maintenance** project requires $184,667 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 certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.
    - **Objectives:** The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs.
    - **Scope:** The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.
    - **Alternatives:** Alternatives considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes**.**
- The **SAP Support Pack Upgrade 2026** project requires $410,658 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 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: Enterprise Core Component ("ECC"), Customer Relationship Manager ("CRM"), Enterprise Portal, Process Orchestration ("PO"), Business Warehouse ("BW"), Business Objects ("BOBJ"), Data Services ("DS"), Solution Manager, Data Quality Manager ("DQM"), Graphical User Interface ("GUI"), Single Sign On ("SSO"), System Landscape Directory ("SLD"), and other related SAP applications.

- **Alternatives:** Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3)Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Secondary Upgrade 2027** project requires $20,308 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 vendor's 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 (Customer Experience Index) goals by improving reliability and performance.

- **Scope:** The project scope is to upgrade 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-23 (SHB-8).

A. Confidential Exhibit A-23 (SHB-8) 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 2026 capital expenditures;
- Column (d) provides total projected 2026 O&M expense;
- Column (e) provides total projected 2027 capital expenditures;
- Column (f) provides total projected 2027 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.

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-23 (SHB-8) 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-23 (SHB-8).

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Projected Test Year O&M
Application Currency-Corporate-Capital	$62,876	$50,301	$5,306
Application Currency-Corporate-O&M	$0	$0	$180,634
Application Currency-Customer-O&M	$0	$0	$69,663
Application Currency-Electric & Gas Shared-Capital	$48,975	$39,180	$217,312
Application Currency-Electric & Gas Shared-O&M	$0	$0	$317,806
Application Currency-Electric-O&M	$0	$0	$287,098
Application Currency-IT/Digital Foundation-Application Platforms-Capital	$97,409	$77,927	$97,268
Application Currency-IT/Digital Foundation-Application Platforms-O&M	$0	$0	$156,695
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	$0	$0	$22,229
Application Currency-Operational Technology-Capital	$80,841	$64,673	$22,920
Application Currency-Operational Technology-O&M	$0	$0	$187,262
Application Currency-Security-Capital	$73,370	$58,696	$6,632
Application Currency-Security-O&M	$0	$0	$209,175

Enhancement Projects

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

A. Exhibit A-24 (SHB-9) is the Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis. Page 1 provides a summary of enhancement projected and actual spend for the years 2020 through 2027. Specifically:

- Column (a) provides the year reference;
- Column (b) identifies the electric case where the projected or actual amounts were provided;
- Column (c) identifies the exhibit number where the projected or actual amounts were provided;
- Columns (d) through (k) identify the projected or actual capital amounts for each year; and
- Columns (l) through (s) identify the projected or actual O&M amounts for each year.

Page 2 provides an analysis of total actual and projected enhancements, total incremental annual worklist of enhancements, total annual demand, total Company cumulative worklist, and electric allocation cumulative worklist. Specifically:

- Column (a) identifies the categories used for analysis, where total amounts include both capital and O&M;
- Columns (b) through (i) identify the projected or actual amounts by year; and
- Column (j) identifies the projected amounts for the test year.

In further detail, by category, the Total Electric Projected and Actual/Projected Spend amounts are derived from Exhibit A-24 (SHB-9), page 1, which are the source for the figures indicated. The Total Company Incremental Annual Worklist, which is broken out in Exhibit A-25 (SHB-10), is defined as the total Company cost of planned enhancement requests received in the year indicated in Exhibit A-24 (SHB-9), page 2. The Total Electric

Allocation Incremental Annual Worklist provides the electric allocation of the total Company incremental worklist. The Total Electric Annual Demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of Total Electric Actual/Projected spend and Total Electric Allocation Incremental Annual Worklist. Total Company Cumulative Worklist is defined as the year-over-year increase of unfulfilled enhancement requests. Total Electric Allocation Cumulative Worklist provides the electric allocation of the Total Company Cumulative Worklist.

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

A. Exhibit A-25 (SHB-10) is the Enhancement Worklist Detail Report. It provides a summary of the Enhancements queue of work requests. Specifically:

- Column (a) provides the Enhancement open date, internally referred to as the Open Date of the request;
- Column (b) identifies the Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Type of request;
- Column (d) provides a Description of Work;

- Column (e) provides the Work State of Submitted, Screening, Qualified, and Approved;
- Column (f) provides the Portfolio that has requested the enhancement;
- Column (g) identifies the Associated Application, which is internally referred to as the Configuration Item, and is the application that will be changed with the Enhancement;
- Column (h) identifies the internal Requestor Department;
- Column (i) provides the Total Estimated Hours, which reflects the planning estimate of work hours entered prior to the start of work request; and
- Column (j) provides the estimated Cost.

Q. How does the Company track and manage enhancements?

A. The Company actively maintains a worklist of enhancements, Exhibit A-25 (SHB-10). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. For an enhancement to seek funding approval, it must be qualified with a cost estimate and benefits to ensure the enhancement is ready for execution. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records is updated by enhancement request coordinators through closure. This provides the Company with an auditable tracking method for every enhancement request.

Q. Please explain the historical demand for enhancements and the Company's projection for future enhancement demand.

A. The demand for enhancement efforts has grown an average of 49% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology.

As of October 2024, the Company has a worklist (Exhibit A-25 (SHB-10)) of 639 Company-wide requests to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in several previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Electric Allocation Cumulative Worklist (Demand) for the test year is $17,999,226 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting $10,120,181 of Total Electric Projected Spend (Exhibit A-24 (SHB-9), page 2, line 2, column j). To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2026 and 2027 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

Q. What methods is the Company using to ensure projected enhancement expenditures and expenses in the test year are reasonable and prudent?

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2022-2024 of $9,564,426 plus known incremental work of $6,801,862 ($16,366,289) and compared it to the projected Test Year enhancement expenditures and expenses of $10,120,181. This validates Test Year projections are in line with historical spending and known incremental work. Then for the total cumulative demand method, the Company compared the Total Electric Allocation Cumulative

Worklist amount of $17,999,226, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of $10,120,181. This comparison validates these projections are in line with the projected demand.

Q. Please further explain the Company's calculation for the cumulative worklist amount.

A. Projections for the total cumulative worklist in 2026 and 2027 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 17% over the past three years. As a result, the cumulative worklist for enhancements (Exhibit A-25 (SHB-10)) continues to grow year over year, as depicted on Exhibit A-24 (SHB-9), page 2, line 7. Validating the projected Enhancement spending based on a known worklist and a three-year historical average of actual spend is an indication that the Company's test year projected spend of $10,120,181 is reasonable and prudent.

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
Energy Assistance Enhancements and Maintenance Annual Updates	$0	$0	$193,086
Product Family Enhancements-Corporate-Capital	$1,454,687	$0	$193,040
Product Family Enhancements-Corporate-O&M	$0	$0	$116,530
Product Family Enhancements-Customer-Capital	$2,365,309	$0	$107,817
Product Family Enhancements-Customer-O&M	$0	$0	$172,976
Product Family Enhancements-Electric & Gas Shared-Capital	$710,841	$0	$96,252
Product Family Enhancements-Electric & Gas Shared-O&M	$0	$0	$124,350
Product Family Enhancements-Electric-Capital	$1,597,161	$0	$242,126
Product Family Enhancements-Electric-O&M	$0	$0	$240,811
Product Family Enhancements-Application Platform Services-Capital	$502,706	$0	$102,957
Product Family Enhancements- Application Platform Services -O&M	$0	$0	$103,502
Product Family Enhancements-Infrastructure Platform Services-Capital	$432,985	$0	$261,025
Product Family Enhancements-Infrastructure Platform Services-O&M	$0	$0	$144,327
Enhancements-Security-Capital	$559,651	$0	$94,628
Enhancements-Security-O&M	$0	$0	$303,412

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 $3,140,597 in capital ($2,512,478 ROM Adjusted Capital) and $538,611 in O&M in the test year.
    - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 ("DL 2.0"), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems

including SingleStore Data Lake ("SSDL"), SAP BW, SAP BOBJ, Native HANA, the BW Portal, and SAP BODS creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.

- **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.

- The **Digital-Infrastructure Automation** project requires $477,554 in capital ($382,043 ROM Adjusted Capital) and $159,902 in O&M in the test year.

  - **Description:** This project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs.

- **Problem Statement:** As the Company uses cloud services to provide infrastructure for applications, the difficulty of manually deploying, maintaining, and decommissioning infrastructure, improving efficiency of the use of infrastructure, bolstering resiliency, maintaining security posture, and extending new capabilities increases significantly. The manual approach lengthens application implementation times and leads to inconsistent and/or incorrect deployment of infrastructure.

- **Objectives:** This project will create value by ensuring the Company's application infrastructure requirements are met through automation. Specifically, the project will create automation to deploy, maintain, and deprovision infrastructure in a modular fashion to be used by product teams to deploy, maintain, upgrade, and deprovision Company applications. Thus, the project will: (1) improve the efficiency of the use of infrastructure by allowing for infrastructure to be provisioned when needed, and deprovisioned when not needed; (2) bolster the resiliency of infrastructure by creating reusable resilient patterns and scalability for applications to use; (3) deploying and removing infrastructure securely; and (4) enhancing or extending automation for new cloud and data center services to support Company applications.

- **Scope:** The project scope includes: (1) procuring automation software; (2) building automation for cloud and data center services; (3) building resiliency and scalability into the services; (4) building security posture into the services; and (5) enhancing existing or extending automation for new services.

- **Alternatives:** Alternatives considered included: (1) manually deploying, maintaining, and decommissioning infrastructure to support Company applications. This alternative was not chosen because it has proven to be slow, costly, and error-prone; (2) manually improving the efficiency in the use of infrastructure. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (3) manually bolstering resiliency. This alternative was not chosen because it has proven to be error-prone; (4) manually maintaining security posture. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (5) manually extending new cloud services. This alternative was not chosen because the services become available faster than the Company can manually deploy them while meeting necessary standards and security postures; (6) and utilizing pre-built tooling without extension or development. This alternative was not chosen because pre-built tooling does not meet the necessary Company standards and security postures; (7) procure automation software and extend the software to meet Company standards. This alternative was selected because the combination provides the most cost-effective method for automation of

existing and new services at speed and scale while allowing the services to be deployed in a secure manner that meets Company standards.

- The **OT Datacenter Migration** project requires $3,343,208 in capital ($2,674,566 ROM Adjusted Capital) and $570,345 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. Please explain the SAP HANA Database Migration project.

A. The SAP HANA Database Migration project 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, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the Company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

- **Objectives:** This project lays the groundwork for the Company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

- **Scope:** Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures, and tools required to manage the newly migrated SAP HANA applications.

- **Alternatives:** Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected; (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept

significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement; (3) Migrate to SAP's 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 is the Company's migration timeline for the SAP HANA Database Migration project?

A. The Company initiated the SAP HANA Database Migration project in April 2023 and is anticipated to be completed by December 2025. The migration will be staggered across 2024 and 2025. In 2024, the Company migrated ancillary systems to HANA to gain valuable insight from these migrations and address any technical issues before migrating the ECC in 2025. This will also provide time to conduct mock migrations for ECC, which will help minimize downtime.

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 $43,491,363 in capital ($34,793,090 ROM Adjusted Capital) and $15,178,194 in O&M in the test year.
  - **Description:** This project will modernize the Company's 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 [redacted] (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 the Company's 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 100 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 16 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.[5] The Activate methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and 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

[5] Available at https://learning.sap.com/learning-journeys/discovering-sap-activate-implementation-tools-and-methodology/describing-sap-activate

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.

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.[6] 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

[6] Available at https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach

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.

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. Assuming the Company begins the project in 2025, 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 version is only available until 2030.

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.[7]

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. How did the Company develop the cost estimate for the SAP S/4HANA Implementation project?

A. The Company developed the 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.

[7] Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364.

- 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.

- 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. 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. Is the Company requesting any special rate-making treatment to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project?

A. Yes. The Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life. This software asset will provide significant value and functionality over an extended period, as it is deeply integrated into the Company's business processes, and there is a substantial investment in its development and integration. The benefits of continuing to use the existing software outweigh the costs of transitioning to new software sooner than

15 years. This approach will also benefit customers by spreading these costs over 15 years to minimize the impact on customer rates.

Q. Please describe Confidential Exhibit A-26 (SHB-11).

A. **Confidential** Exhibit A-26 (SHB-11) is the IT S/4HANA Cloud Implementation Costs balance for Electric and Common investments for the projected 13 months ending April 30, 2027. It provides a summary of the electric allocation of projected IT Department investments expenditures. Specifically:

- Column (a) provides the balance category;
- Columns (b) through (n) provide each month's ending IT S/4HANA Cloud Implementation Costs balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Confidential Exhibit A-26 (SHB-11).

A. The Company has identified cloud computing as a viable alternative for several technology solutions associated with the SAP S/4HANA Implementation project. As discussed previously, the Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life and adjusting working capital. Cloud implementation costs are projected based on the planned implementations of the SaaS solution associated with the SAP S/4HANA Implementation project. This working capital adjustment is provided by Company witness Daly on Exhibit A-12 (PDD-34), Schedule B-4.

Q. Is the Company requesting any additional special rate-making treatment for the SAP S/4HANA Implementation project's IT Investments O&M expense?

A. Yes. The Company is also requesting to defer the IT Investments O&M expense associated with the SAP S/4HANA Implementation project and recover the expense over the life of

the asset. This approach will benefit the customers by spreading these costs over the life of the asset to minimize the immediate impact on customer rates. This proposal will be discussed further in the direct testimony of Company witness Daly.

Q. Are there any Digital Foundations and Capabilities projects with disallowances from Case No. U-21585 that you would like to discuss?

A. Yes. The following Digital Foundations and Capabilities projects are addressed below.

- IT Operations Management - Service Operations;
- Operational Technology - Service Management Upgrade;
- Software Asset - Service Management Upgrade; and
- SolarWinds Performance Monitoring Expansion Upgrade.

Q. Please briefly describe the IT Operations Management - Service Operations project.

A. This project provides the Company access to a service mapping tool that leverages infrastructure data to identify all assets that support a service, with information about the service-specific relationship.

Q. Please briefly describe the Operational Technology - Service Management Upgrade project.

A. This project provides the Company service management capabilities for Operational Technology, to automate asset tracking, maintenance, and incident management for the operational technology assets.

Q. Please briefly describe the Software Asset - Service Management Upgrade project.

A. This project will give the Company automated monitoring, assessment, and oversight of software licenses and compliance to optimize software license management.

Q. Please briefly describe the SolarWinds Performance Monitoring Expansion Upgrade project.

A. This project provides the Company an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance.

Q. What was the partial disallowance for the four Digital Foundations and Capabilities projects discussed above in Case No. U-21585?

A. The partial disallowance for the four Digital Foundations and Capabilities projects discussed above in Case No. U-21585 was a 20% disallowance of the 2024 projected amount ($444,197) of $88,839.

Q. What was the Commission's reason for partial disallowance of the four Digital Foundations and Capabilities projects 2024 projected amounts?

A. The Commission's reason for partial disallowance of the four Digital Foundations and Capabilities projects is the projects' 2024 projected cost estimates of $444,197 was not adequately supported.

Q. Did Staff oppose the four Digital Foundations and Capabilities projects?

A. No. Staff did not oppose the four Digital Foundations and Capabilities projects.

Q. Is the Company requesting full recovery of the actual 2024 costs for the four Digital Foundations and Capabilities projects in this case?

A. Yes, the Company is requesting full recovery of the actual 2024 costs provided in the table below for the four Digital Foundations and Capabilities projects in this case.

Project	Capital 2024 Actuals	Confidential Exhibit A-20 (SHB-5) Reference
IT Operations Management – Service Operations	$139,403	Line No. 73, column l
Operational Technology – Service Management Upgrade	$115,849	Line No. 75, column l
Software Asset – Service Management Upgrade	$49,003	Line No. 82, column l
SolarWinds Performance Monitoring Expansion Upgrade	$2,743	Line No. 84, column l

Security Projects

Q. Please explain the Security projects.

A. Below are the Security projects:

- The **Business Continuity - Program Management Tool** project requires $50,579 in O&M in the test year.
  - **Description:** The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.
  - **Problem Statement:** The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream/downstream impact mapping, Incident Command System ("ICS") documentation automation, and user administration.
  - **Objectives:** This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized, and expedient response process (ICS) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restoration gaps between critical

business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

- **Scope:** The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, ICS, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency ("FEMA") National Incident Management System ("NIMS"); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process.

- **Alternatives:** Alternatives considered included: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption; (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this; (3) Implement a best-in-class SaaS solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA ICS. This alternative was selected because there are better SaaS solutions that fit the needs outlined above.

- The **Forward Web Proxy Services** project requires $2,048,658 in capital ($1,638,926 ROM Adjusted Capital) and $201,735 in O&M in the test year.

  - **Description:** This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

- **Problem Statement:** The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SaaS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.

- **Objectives:** This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.

- **Scope:** The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SaaS cloud vendors.

- **Alternatives:** The Security team did extensive research on alternative web proxy services solutions. Alternatives considered included: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation, the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's capabilities.

- The **Physical Access Management and Alarm Response** project requires $1,832,660 in capital ($1,466,128 ROM Adjusted Capital) and $168,119 in O&M in the test year.

  - **Description:** The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user

identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

- **Problem Statement:** The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

- **Objectives:** This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

- **Scope:** The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will

require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

- **Alternatives:** Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term costs, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

- The **Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation** project requires $432,685 in capital and $24,936 in O&M in the test year.

  - **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; (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.

- The **Security/OT Field Modernization** project requires $149,231 in capital ($119,385 ROM Adjusted Capital) and $45,452 in O&M in the test year.

  - **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.

  - **Problem Statement:** Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and

contractors have access to the Company's critical infrastructure using non-Company laptops. 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; (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. 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-21870

REVISED REBUTTAL TESTIMONY

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Patrick D. Daly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Patrick D. Daly who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to:

- Respond to Attorney General ("AG") witness Sebastian Coppola's recommendations regarding the accounting treatment of the Company's SAP S4/HANA project;
- Address arguments and recommendations from AG witness Coppola and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch concerning the Company's Low Voltage Distribution ("LVD") forestry ramp-up proposal;
- Rebut recommendations from Natural Resources Defense Council, Sierra Club, and CUB (collectively "MNSC") witness Douglas B. Jester related to the Company's LVD pole replacement investments;
- Respond to AG witness Coppola's recommendation regarding the Company's working capital cash balance; and
- Present an adjusted revenue deficiency reflecting the revised rebuttal position of Consumers Energy witnesses.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-208 (PDD-63)	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-209 (PDD-64)	Adjusted Rate Base for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-210 (PDD-65)	Adjusted Utility Plant for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-211 (PDD-66)	Capital Spending Reconciliation for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-212 (PDD-67)	Adjusted Working Capital for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-213 (PDD-68)	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-214 (PDD-69)	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-215 (PDD-70)	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-216 (PDD-71)	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027; and
Exhibit A-217 (PDD-72)	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027.

Q. Are there any statements you would like to make regarding your rebuttal testimony?

A. Yes. Items not specifically addressed in my rebuttal testimony should not be construed to indicate my agreement with them.

Accounting for SAP S4/HANA

Q. Please describe AG witness Coppola's recommendations regarding the SAP S4/HANA project.

A. On page 95 of his direct testimony, Mr. Coppola indicates that the project is too premature to justify including any capital expenditures in this rate case. He also recommends the Commission reject the Company's proposal to defer forecasted operating and maintenance ("O&M") costs into a regulatory asset citing his perception of a lack of firm project execution plans. Additionally, while not explicitly addressed, Mr. Coppola appears to

oppose the Company's accounting proposal to extend the amortization period for the cloud implementation costs related to the SAP S4/HANA Software as a Solution ("SaaS") solutions to 15 years.

Q. Does the Company agree that SAP S4/HANA costs should not be included in this case?

A. No. Company witness Stacy H. Baker continues to support the inclusion of the SAP S4/HANA project, as outlined in her rebuttal testimony.

Q. Do you agree with Mr. Coppola that the accounting requests related to the SAP S4/HANA project should be denied?

A. No. As explained in my direct testimony, approving the deferral of O&M expenses will allow the Company to align cost recovery with the period over which the project delivers benefits. The same rationale applies to the request to amortize cloud implementation costs over 15 years. These proposals help mitigate customer rate impact by smoothing expenses over the life of the project. Mr. Coppola offers no specific critique of these accounting requests beyond asserting that the project is too preliminary for inclusion in this case.

Q. Has the Commission previously approved the Company's requested accounting treatment for SAP S4/HANA investments?

A. Yes. In the Commission's September 30, 2025 Order in Consumers Energy's gas rate case, Case No. U-21806, the Commission agreed with Consumers and found "*the company's request to defer investment O&M expense over the 15-year life of the project and to amortize cloud computing costs associated with the project over the same 15-year period will lessen impacts to customer rates*" (page 226). This supports the Company's proposed accounting treatment, and I recommend the Commission reject Mr. Coppola's proposal.

LVD Forestry Ramp Up

Q. Please describe the Company's proposal with respect to its LVD Line Clearing Program expenditures in this case.

A. As outlined in my direct testimony, the Company is proposing to increase its LVD Line Clearing Program O&M expenditures significantly above historical levels to obtain a five-year clearing cycle and more aggressive line clearing on targeted three-phase primary lines. Additionally, the Company requested approval to defer "ramp-up" or "incremental expenditures" above a defined "baseline" expense as a regulatory asset once the ramp-up begins and through its completion (i.e. beginning in 2026 and through the 2030-2031 test period). As explained in my direct testimony, the benefit of this proposal is to better match the benefits provided by the "ramp-up" to the recovery of costs and to mitigate rate impact to customers.

Q. Did the MPSC Staff ("Staff") or other intervenors oppose the Company's proposed "ramp-up" spending levels or the request to defer such costs to a regulatory asset?

A. No. In fact, there is broad support for the Company's total proposed LVD O&M expenses and the proposal to defer "ramp-up" costs to a regulatory asset. The following excerpts from the parties' testimony illustrate this support:

- AG witness Coppola, "*agree[s] in principle with the proposal to defer the line or tree clearing costs above a reasonable threshold*" (page 174, lines 14 to 15).
- CUB witness Bunch testified, "*I support the Company's operational plan and spending level, which I consider to be consistent with the recommendations of the Liberty Audit. I also agree that the line clearing surge costs should be held as regulatory assets*" (page 39, lines 12 to 14).
- Staff witness Duell indicated, "*Staff supports the requested $186,684,000 for the projected test year O&M expense. It is crucial to allow Consumers to spend the full amount for line clearing to increase the resiliency of Consumers Energy's electric distribution system"* (page 7, lines 23 to 25) and

"*Staff supports the Company's proposal to recover LVD line clearing O&M spending in the test period as a regulatory asset*" (page 8, lines 16 to 17).

Given the absence of opposition and broad support from intervenors, I recommend the Commission approve the Company's proposal to defer ramp-up forestry costs as a regulatory asset.

Q. Is there any opposition to the Company's proposed cost recovery mechanism for the resulting forestry "ramp-up" regulatory asset?

A. Yes. As explained in my direct testimony, the Company proposed securitizing the regulatory asset once it reaches an appropriate balance. This was conditional upon receiving a return on the regulatory asset at the Company's prevailing weighted average cost of capital ("WACC") during the "ramp-up" period and until securitization takes place. However, both Staff witness Duell and AG witness Coppola opposed this approach, contending that the Company should only earn a return at its short-term debt rate. Company witness Marc R. Bleckman addresses these concerns in his rebuttal testimony, reaffirming support for the Company's original cost recovery proposal and defending the use of WACC as a fair and reasonable return.

Q. Please describe any other opposition raised with respect to the Company's forestry "ramp-up" proposal.

A. Baseline expenses represent the amount of funding that is included in rates for the test year. Under the Company's proposal, any expenses incurred above the defined baseline would be deferred to the regulatory asset. On page 174 on his direct testimony, AG witness Coppola asserts that the Company has calculated "baseline" O&M expenses that are too high, which results in a reduced opportunity to defer and securitize a higher amount of tree clearing costs. CUB witness Bunch makes a similar assertion on pages 39 through 40 of

his direct testimony, arguing the Company's approach to calculate the "baseline" O&M expense is speculative.

Q. How did AG witness Coppola and CUB witness Bunch develop their proposed LVD Line Clearing O&M baseline?

A. On page 175 of his direct testimony, Mr. Coppola indicates that the historical period (2024) forestry expenses represents a reasonable baseline of tree clearing expenses for the projected test year "baseline." Mr. Bunch also utilizes 2024 historical spend but adjusts the baseline figure for inflation factors to arrive at the projected test year amount as described on page 40 of his direct testimony.

Q. Do you agree with this approach?

A. I do not. The approach taken by AG witness Coppola and CUB witness Bunch is overly simplistic and fails to reflect the operational and strategic planning embedded in the Company's acceleration to a five-year LVD line clearing cycle as supported by Company witness Sara E. Stewart's direct and rebuttal testimony. Mr. Coppola and Mr. Bunch's reliance on 2024 historical spending, either directly or with minimal inflation adjustments, ignores the Company's demonstration that the cost of achieving the ramp-up (and the resulting future "steady-state maintenance" of the cycle) is significantly higher than maintaining historical levels of expense in which the Company was on a seven-year effective cycle. Their approach disregards changes that are appropriately considered in a projected test year. The use of a projected test year is intended to account for such forward-looking changes.

Company witness Stewart provided detailed direct testimony outlining the fundamental shift in operations required to transition to a five-year LVD line clearing

cycle. Her testimony also supported the estimated annual expense to maintain the LVD system on a five-year cycle in a steady state once the cycle is achieved in 2031. The expense assumptions within her testimony and supporting exhibits were built on factors such as overall crew resourcing, the elimination of all back-log miles, the consideration of overtime for both local and out-of-state tree crews, among other items. The projected test year "baseline" expense was derived from this forward-looking analysis and brought back to test period dollars. Notably, no intervenor disputed the Company's total LVD Line Clearing O&M request for the projected test period, which was built utilizing these assumptions.

The methodology proposed by Mr. Coppola and Mr. Bunch appears designed to suppress the test year "baseline," thereby limiting the Company's ability to recover a substantial portion of O&M costs within the LVD expense included in base rates. Company witness Bleckman's rebuttal testimony describes the negative credit implications of adopting a lower baseline. Coupled with Mr. Coppola's proposal to allow only a short-term debt rate on the regulatory asset, this punitive approach undermines the reliability goals of the program which have broad support in this case and are consistent with the Liberty Consulting Group ("Liberty") Audit recommendations adopted by the Commission. Additionally, the methodology used to establish the baseline should be weighed against the Company's deliberate effort to balance reliability improvements with customer affordability. Once again, by deferring and securitizing these costs, the Company is mitigating immediate customer rate impacts.

For these reasons, the baseline methodology proposed by Mr. Coppola and Mr. Bunch lacks merit. I continue to support Company witness Stewart's approach to

calculating the LVD baseline expense for the test year as reasonable, well-supported by the evidence in this case, and aligned with long-term reliability objectives. I recommend that the Commission adopt the Company's methodology for calculating the LVD baseline line clearing expenses and reject the alternative proposals offered by Mr. Coppola and Mr. Bunch.

Q. Do you have any final observations related to Mr. Coppola and Mr. Bunch's recommendation for the proposed baseline level of forestry expense?

A. Yes. As discussed above, Mr. Coppola uses the Company's actual 2024 forestry spend of $110.2 million as the basis for his proposed baseline. On page 40 of his direct testimony, Mr. Bunch applies an inflation adjustment to the Company's 2024 actual forestry expense to yield a baseline of approximately $114 million.

Company witness Stewart's direct testimony, specifically Figure 20, outlines authorized and actual forestry spending across the Company's five most recent rate cases. This data shows a consistent upward trend, reflecting the Company's commitment to achieving a shorter forestry cycle. In the Company's most recent rate case, Case No. U-21585, the Commission authorized the Company to spend approximately $125 million in forestry. This currently authorized amount is in excess of Mr. Coppola and Mr. Bunch's proposed baseline amounts. The continued upward trend in both actual and authorized spending supports the reasonableness of the Company's proposed baseline. It would be unreasonable to set the baseline level of forestry expense below currently authorized spending levels, particularly as the Company transitions to a more aggressive five-year forestry cycle that requires increased investment. Therefore, Mr. Coppola and Mr. Bunch's proposed baseline levels are too low and should be rejected by the Commission.

LVD Pole Replacement Surge Proposal

Q. What does MNSC witness Jester recommend with respect to LVD pole replacements?

A. On page 16 of his direct testimony, Mr. Jester recommends the Commission order the Company to defer and propose securitization of its projected spending for a surge in LVD pole replacements. Mr. Jester proposes a baseline spending amount for LVD pole replacements of $25 million and recommends that all pole replacement costs exceeding this amount be considered as surge expenditures.

Q. How do you respond?

A. I disagree with Mr. Jester's proposal. First, the Company objects to the use of securitizations for these investments in its distribution system. Historically, utility securitizations have been reserved for the recovery of stranded costs associated with assets that no longer provide a benefit to customers and/or material non-recurring expenses. The decision to propose securitization for the forestry ramp up expenditures was made to mitigate the rate impacts from the increase in this operating expense. It was also intended to spread the cost to customers more evenly over the time horizon of the anticipated benefits.

Unlike line clearing, which is a recurring operational expense, capital investments such as LVD pole replacements result in long-lived assets that provide long-term benefit to customers and merit inclusion in the Company's permanent capital structure. These expenditures should be recovered through traditional rate base treatment, allowing for depreciation over time and proper cost allocation across the customers who benefit. For these reasons, I recommend the Commission reject Mr. Jester's proposal.

Working Capital Cash Balance

Q. Please describe AG witness Coppola's recommendations regarding the Company's cash balance included in working capital.

A. On pages 102 through 103 of his direct testimony, Mr. Coppola recommends that the Company's projected test year cash balance included in working capital of $50.4 million be reduced by $41.4 million to $9.0 million. He arrives at this figure by first calculating a three-year average cash balance of $25.1 million, then removing $16.1 million of cash held in interest-bearing accounts, which he argues should not be included in working capital. Mr. Coppola asserts that his calculation of a $9.0 million cash balance more accurately reflects the Company's operational cash needs.

Q. How do you respond?

A. I do not agree with Mr. Coppola's proposed methodology. Company witness Bleckman refutes the AG's position with respect to the Company's projected cash balance of $50.4 million. Furthermore, even if the Commission were to reject the Company's methodology to calculate its projected working capital cash balance, it should not adopt Mr. Coppola's flawed proposal.

First, it is inappropriate to exclude cash held in interest-bearing accounts from the working capital calculation. These funds are maintained in unrestricted operating accounts and are readily available to meet the Company's short-term liquidity and operational needs. Moreover, the interest income generated from these accounts is included as a direct offset to the revenue requirement. This treatment is reflected in the projected Net Operating Income shown on Exhibit A-13 (PDD-37), line 6.

Second, even if the Commission rejected the Company's proposed approach as described by Company witness Bleckman, which it should not, then the appropriate cash balance should be the historical 13-month average of $36.4 million as shown on Exhibit A-12 (PDD-34), line 1 (column d), not a three-year average balance as proposed by Mr. Coppola. It is the long-standing practice of the Company, and one accepted by the Commission, to calculate working capital utilizing a 13-month average of historical balances. Mr. Coppola's methodology results in an understatement of the Company's actual working capital cash needs.

I recommend the Commission reject Mr. Coppola's arguments and adopt the Company's as-filed capital cash balance of $50.4 million as supported by Company witness Bleckman.

Adjusted Revenue Deficiency

Q. Please describe Exhibits A-208 (PDD-63) through A-217 (PDD-72).

A. Exhibits A-208 (PDD-63) through A-217 (PDD-72) present the calculation of the Company's adjusted revenue deficiency for the projected 12-month period ending April 30, 2027. As shown on Exhibit A-208 (PDD-63), line 10, column (e), the Company has recalculated a test year revenue deficiency of $~~407.7~~ 422.9 million, a reduction of $~~28.2~~ 13.0 million from the Company's original filing in this case.

Q. Why is the Company proposing an adjusted test year revenue deficiency?

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make certain adjustments.

Q. Please summarize the proposed adjustments to the revenue deficiency.

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. Total decrease to net utility plant of $37.2 million, depreciation expense of $1.3 million, and property taxes of $0.5 million. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-210 (PDD-65) and Exhibit A-211 (PDD-66);

2. Total decrease of $0.7 million to other O&M. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-215 (PDD-70); and

3. A decrease in the Company's calculation of overall cost of capital from 6.35% to 6.30% as described in the rebuttal testimony of Company witness Bleckman.

Q. Does this conclude your rebuttal 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-21870

REVISED EXHIBITS

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

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

Case No.: U-21870
Revised Exhibit No.: A-208 (PDD-63)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,367,518	(37,159)	15,330,358
2	Adjusted Net Operating Income	Revised Exhibit No.: A-213 (PDD-68)	707,746	(100)	707,646
3	Overall Rate of Return	Line 2 / line 1	4.61%	0.01%	4.62%
4	Required Rate of Return	Exhibit No.: A-187 (MRB-22)	6.35%	-0.05%	6.30%
5	Income Required	Line 1 * line 4	975,589	(9,433)	966,156
6	Income Deficiency (Sufficiency)	Line 5 - line 2	267,843	(9,332)	258,510
7	Revenue Conversion Factor		1.3381	1.3381	1.3381
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	358,395	(12,488)	345,907
9	Return On - Campbell Regulatory Asset	Ex. A-81 (PDD-57), Line 5	77,486	(502)	76,984
10	Adjusted revenue deficiency (sufficiency)	Line 8 + Line 9	435,881	(12,989)	422,891

Notes

{1} Source: Exhibit No.: A-11 (PDD-28)

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

Case No.: U-21870
Revised Exhibit No.: A-213 (PDD-68)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Sales Revenues	4,758,415	-	4,758,415
2	Other Revenues	262,208	-	262,208
3	Total Operating Revenue	5,020,623	-	5,020,623
4	Power supply costs	2,313,242	-	2,313,242
5	Other O&M Expense	804,952	(694)	804,259
6	Depreciation and Amortization	813,088	(1,294)	811,793
7	Property Taxes	280,500	(511)	279,989
8	General Taxes	36,638	-	36,638
9	Other (Local) Taxes	1,150	16	1,167
10	State Income Tax	33,324	539	33,863
11	Federal Income Tax	46,009	2,043	48,052
12	Total Operating Expenses	4,328,903	100	4,329,004
13	Net Operating Income	691,720	(100)	691,619
14	AFUDC	16,026	-	16,026
15	Net Operating Income, Including AFUDC	707,746	(100)	707,646
	Net Operating Income Adjustments			
16	Income Tax Effect of Interest {3}	---- Included in Lines 12, 13, and 14 ----		
17	Interest Synchronization Adjustment {3}	---- Included in Lines 12, 13, and 14 ----		
18	Total Adjusted Net Operating Income	707,746	(100)	707,646

Notes

{1} Source: Col.(b): Exhibit No.: A-13 (PDD-36)
{2} Source: Col.(c): Revised Exhibit No.: A-214 (PDD-69)
{3} Income tax effects of interest and interest synchronization adjustments are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Revised Exhibit Nos.: A-216 (PDD-71) and A-217 (PDD-72)

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

Case No.: U-21870
Revised Exhibit No.: A-214 (PDD-69)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Sales Revenues	(d) Other Revenues	(e) Pwr Supply Costs	(f) Other O&M	(g) Deprec. & Amort.	(h) Property Taxes	(i) General Taxes	(j) CIT	(k) SIT	(l) FIT	(m) NOI	(n) AFUDC	(o) Adjusted NOI
1	Adjusted Net Operating Income - Initial Filing	Exhibit No.: A-13 (PDD-36)	4,758,415	262,208	2,313,242	804,952	813,088	280,500	36,638	1,150	33,324	46,009	691,720	16,026	707,746
	Adjustments														
2	HVD Lines Reliability	AG - Coppola	-	-	-	(677)	-	-	-	1	35	134	506	-	506
3	Product Family Enhancements - Customer - Capital (Web Rebate for Personalization)	Staff witness Zichi	-	-	-	(17)	-	-	-	0	1	3	12	-	12
4	Depreciation	Exhibit No.: A-211 (PDD-66) col.(n)	-	-	-	-	(1,294)	-	-	2	68	257	967	-	967
5	Property Tax Expense	Exhibit No.: A-211 (PDD-66) col.(o)	-	-	-	-	-	(511)	-	1	27	101	382	-	382
6	General Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Income Tax Effect of Interest	Revised Exhibit No.: A-216 (PDD-71)	-	-	-	-	-	-	-	12	406	1,538	(1,957)	-	(1,957)
8	Interest Synchronization Adjustment	Revised Exhibit No.: A-217 (PDD-72)	-	-	-	-	-	-	-	0	2	8	(11)	-	(11)
9	Total Adjustments	Sum of lines 2 through 8	-	-	-	(694)	(1,294)	(511)	-	16	539	2,043	(100)	-	(100)
10	Adjusted Net Operating Income - Rebuttal Position	Line 1 + line 9	4,758,415	262,208	2,313,242	804,259	811,793	279,989	36,638	1,167	33,863	48,052	691,619	16,026	707,646

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

Case No.: U-21870
Revised Exhibit No.: A-216 (PDD-71)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	Weighted Cost of Debt, Excluding JDITC	Exhibit No.: A-187 (MRB-22)	0.0186
3	Allowable Interest Expense	Line 1 * Line 2	285,481
4	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-49)	293,225
5	Increase/ (Decrease) In Allowable Interest Deduction	Line 3 - Line 4	(7,744)
6	Impact on Taxable Income	Line 5 * -1	7,744
7	Impact on Local Income Taxes	Line 6 * Local Income Tax Rate	12
8	Impact on State Income Taxes	Line 6 * State Income Tax Rate	406
9	Impact on Federal Taxable Income	Line 6 - Line 7 - line 8	7,326
10	Impact on Federal Income Tax	Line 9 * Federal Income Tax Rate	1,538
11	Impact on Net Operating Income	(Line 7 + Line 8 + Line 10) *-1	(1,957)

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

Case No.: U-21870
Revised Exhibit No.: A-217 (PDD-72)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	JDITC Debt-Related Portion of the Capital Structure	Exhibit No.: A-187 (MRB-22)	0.0023
3	Portion of Rate Base Funded by JDITC	Line 1 * Line 2	34,903
4	Cost of JDITC - Debt Portion	Exhibit No.: A-187 (MRB-22)	0.0443
5	Allowable JDITC Interest Expense	Line 3 * Line 4	1,545
6	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-50)	1,588
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	Line 5 - Line 6	(43)
8	Impact on Taxable Income	Line 7 * -1	43
9	Impact on Local Income Tax	Line 8 * Local Income Tax Rate	0
10	Impact on State Income Tax	Line 8 * State Income Tax Rate	2
11	Impact on Federal Taxable Income	Line 8 - Line 9 - line 10	40
12	Impact on Federal Income Tax	Line 11 * Federal Income Tax Rate	8
13	Impact on Net Operating Income	(Line 9 + Line 10 + Line 12) *-1	(11)

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

REVISED DIRECT TESTIMONY

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Jeffrey A. Myrom, 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 Electric Vehicle Customer Programs.

Q. What are your responsibilities as Director of Electric Vehicle Customer Programs?

A. As Director of Transportation Electrification Programs ("TEPs"), I lead the teams for Consumers Energy's PowerMIDrive Residential, PowerMIDrive Public Charging, and PowerMIFleet customer programs.

Q. Please describe your educational background and professional experience.

A. I have a Master of Science Degree in Environmental Policy from Michigan Technological University, and a Bachelor of Chemistry, Environmental Science and General Science from Coe College.

From 2001 to 2006 I served as Deputy Bureau Chief of the Iowa Department of Natural Resources' Energy & Waste Management Bureau ("Bureau"). In that role, I directed all administrative rules processes and amendments for the Bureau. I also represented the Bureau in matters before the Environmental Protection Commission and Iowa Legislature on policy and administrative rules issues.

In 2006, I became employed by MidAmerican Energy, now known as Berkshire Hathaway Energy. In that position, I served as Senior Environmental Policy Analyst, representing MidAmerican Energy on issues related to waste, water, climate, renewable energy, and electric generation resource modeling and planning.

In January 2013, I was employed by Consumers Energy Company as Director of Environmental Regulations, Strategy, and Sustainability. In May 2018, I was promoted to Director of Renewable Energy and Electric Vehicle Customer Products. In this position, I was responsible for administering and expanding the Company's Voluntary Green Pricing programs. Additionally, under my direction, the Company successfully launched the PowerMIDrive pilot in June 2019, approved by the Michigan Public Service Commission ("MPSC" or the "Commission") in Case No. U-20134, and later approved as a permanent residential program in Case No. U-21224. In June 2021, under my direction, the Company also successfully launched the PowerMIFleet pilot that was approved by the Commission in Case No. U-20697, and expanded for fleets serving income qualified communities in Case No. U-20963.

In July 2021, I was promoted to my current position as Director of Electric Vehicle Customer Products. In this position my responsibilities were expanded with the growing pilots, and now include additional team members for the administration of PowerMIFleet, PowerMIDrive Public Charging and PowerMIDrive Residential as permanent programs in the Company's TEP that will benefit all customers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose enhancements to the TEPs that will continue to improve customer experience and benefits without any budgetary increase from prior MPSC approvals. For this testimony, the term electric vehicle ("EV") will be used to collectively describe all forms of EVs, including battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs").

Q. Have you previously testified before the Commission?

A. Yes, I have previously provided testimony in the Company's 2019 Voluntary Green Pricing application (Case No. U-20649), 2021 Renewable Energy Plan amendment (Case No. U-20984), 2021 General Electric Rate Case (Case No. U-20963), 2022 General Electric Rate Case (Case No. U-21224), 2023 General Electric Rate Case (Case No. U-21389), and 2024 General Electric Rate Case (Case No. U-21585).

Q. Are you sponsoring exhibits in this case?

A. Yes, I am sponsoring three exhibits:

Exhibit A-12 (JAM-1)	Schedule B-5.8	Transportation Electrification Plan Capital Expenditures;
Exhibit A-164 (JAM-2)		Transportation Electrification Plan Deferred Asset Costs; and
Exhibit A-165 (JAM-3)		Transportation Electrification Plan Cost Benefit Analysis.

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

A. Yes.

Q. Please describe Exhibit A-12 (JAM-1), Schedule B-5.8.

A. Exhibit A-12 (JAM-1), Schedule B-5.8 reflects the capital spend for the historical, bridge, and test years for the TEPs 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-164 (JAM-2).

A. Exhibit A-164 (JAM-2) shows spending in this case for TEPs' assets, per approvals from prior rate cases. Again, no additional spend from prior approvals is requested.

Q. Please describe Exhibit A-165 (JAM-3).

A. Exhibit A-165 (JAM-3) summarizes the costs and revenues from optimized EV load growth via the TEPs. The positive NPV clearly shows that the additional load growth from EVs creates margin that exceeds the TEPs revenue requirement and other costs. Thus, the TEPs do not increase rates but instead mitigate rate pressure for all customers.

Q. Please summarize the Company's approved TEP programs and their results.

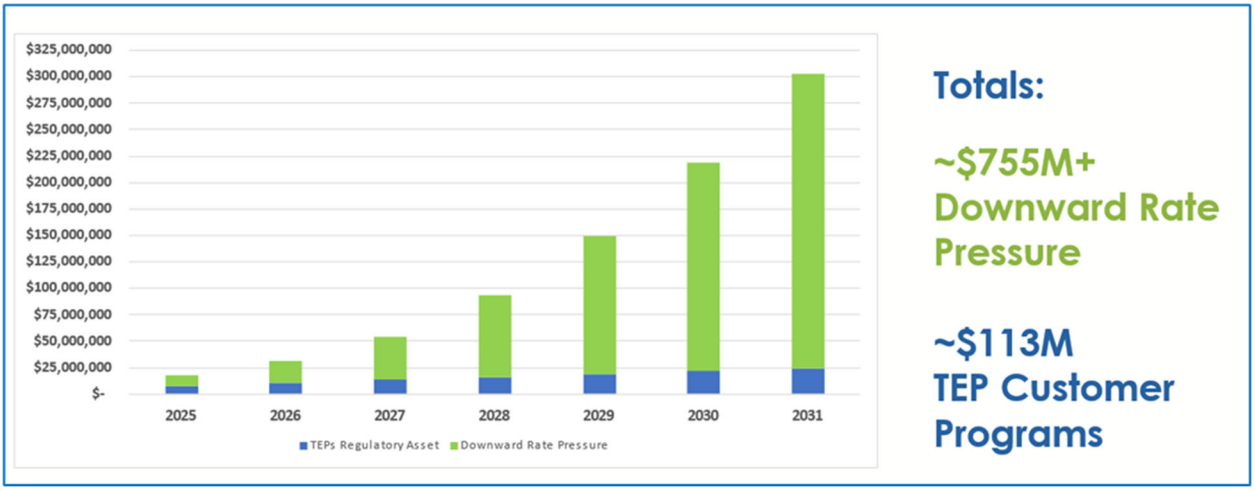
A. Per the Final TEP Order in Case No. U-21492,[1] the Company TEP is centered on long-term strategies to optimize EV charging load to the benefit of all customers, and investments, incentives, programs, and expenditures that are reasonably expected to increase transportation electrification in the Company's electric service territory. The Company's latest TEP is publicly available online[2] and while filed prior to the Final Order via Case No. U-21492, is recognized by the Commission as sufficient for planning purposes until July of 2026, by which time an updated TEP will be filed by the Company.

To accomplish the goals of optimizing load and increasing transportation electrification, the Company continues to support utilizing a portion of the additional

[1] MPSC Case No. U-21492, January 23, 2025 Order, at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X2NGsAAN (adopting the final Transportation Electrification Plan Filing Requirements as filed by the MPSC Staff on January 24, 2025.

[2] MPSC Case No. U-21538, June 25, 2024 Consumers Energy Transportation Electrification Plan 2024 (2024 TEP Report), at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH.

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 pressure. This is clearly shown in the "Cost Benefit Analysis" tab of Exhibit A-165 (JAM-3) and illustrated in the graphic below by comparing the TEPs cost recovery from line 1 in blue, to the total remaining margin after all costs from line 22 in green.



Furthermore, the Company has been highly successful at optimizing EV load growth via its TEP, exceeding the State goal of 80% or more off-peak charging.[3] In fact, in 2023 the Company won the Peak Load Management Alliance Pacesetter award for the best utility EV load management program in the United States, given that residential participants (the largest component of the TEPs) commonly achieves near 95% off-peak charging. Moreover, in early 2025, the Company won the Electric Power Research Institute's ("EPRI's") Technology Transfer Award for applying EPRI and Company

[3] See 2024 TEP Report, page 39, at 0688y00000EFQgtAAH.

research and converting it into load management and EV planning success. The Company's TEP is a national model for EV load management.

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:

Residential – Being able to reliably and cost-effectively charge at home is critical for most EV drivers, thereby directly impacting EV adoption because if you don't have convenient home charging you 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, Time-of-Use ("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 is presently implementing a referral incentive program, as the most likely people to purchase an EV are those who know someone with an EV, and thus customers in the program are key components of helping to grow

enrollment via other EV drivers and potential drivers they know. Finally, the team is also presently implementing the dual-cord L2 and splitter incentive,[4] 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.

Critically, the Company's residential programming also focuses on multifamily locations, providing equitable charging opportunities at apartments, condos, and townhomes where charging infrastructure is known to be harder to implement. Approximately one in three customers is estimated to live in a multifamily property and with very affordable, used EVs rapidly increasing in market availability, this is an important segment to ensure service for.

In multifamily situations where a customer's residential L2 cannot be directly tied to their meter and parking location, the Company offers up to a $7,500 rebate to add a separate service with at least two plugs powered by 100 amps. The new separate service is usually in a shared parking area, although site hosts can choose if they want to create reserved parking spots and can choose if and how to recoup costs for L2 utilization by residents. The Company also provides signs for display at the charger encouraging

[4] 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.

off-peak charging, literature for property managers relaying the same message, and a $20 per month bill credit for 12 months when 80% or more of charging is off-peak. Given tenant turnover challenges, the Company is considering if more active but low-cost controls, such as timers to avoid weekday peak hours, may be useful tools to promote off-peak charging as more load data continues to be gathered.

Public – Public charging advances both grid optimization and EV adoption. Grid optimization is achieved by incentivizing lower-power charging (L2 and L1) at strategic off-peak locations that fit the customer's use case. A few examples of such off-peak use cases supported by the Company TEP include utilizing a L2 community charger on the weekend or overnight if your multifamily property does not offer charging, using a hotel L2 overnight while on business travel or a campground L2 when family vacationing at our excellent state parks on the Lake Michigan Circuit,[5] or using an L1 at the airport or ferry station when away on a multi-day trip.

Such public charging also assists with EV adoption because knowing a charger exists where you want to travel instills charging confidence, and charging confidence is the inverse of range anxiety (which remains one of the top three concerns regarding EV adoption). Moreover, when public charging resources do not exist at such key locations, existing EV drivers are more likely to not take their EV on the longer trip, which reinforces the stereotype that EVs are only for around town and thus not ready for mainstream adoption.

Like the residential multifamily strategy, public L2 and L1 programs utilize educational outreach materials and signage for site hosts, TOU rates, and rebates for

[5] The "Lake Michigan Circuit" is an initiative by Michigan, Wisconsin, Illinois, and Indiana to build EV charging infrastructure along Lake Michigan to support tourism on the coastline.

off-peak charging of up to $7,500 per two L2 plugs or five L1 plugs powered by 100 amps. These power levels serve to spread out the load and optimize off-peak utilization of the distribution system.

Furthermore, community charging also promotes equity. It encourages developers to reach areas that might otherwise lack access to lower-power charging by creating L2 infrastructure within walking distance of multifamily residences.

Fleet – Fleet and workplace charging also directly address grid optimization and EV adoption. For example, workplace charging is not only largely off-peak (typical commutes can finish charging before noon) but also enables EV adoption by customers who may not have access to charging at their home (which is especially challenging for multifamily residents). Moreover, the fleet program presently focuses on outreach, TOU rate, and rebate programs for small and medium businesses, local governments, non-profits, and educational institutions to incentivize off-peak charging. The additional funding for fleets serving income-qualified customers will continue to allow non-profits and local governments to add cost-effective EVs to their fleet that they may not have been able to afford without the funding. Finally, employees who are exposed to the performance benefits of EVs at work are more likely to buy or lease an EV as their next personal vehicle, thereby increasing EV adoption.

The Company's fleet and workplace rebates are up to $7,500 per two plugs powered by 100 amps, with an enhanced rebate of up to $10,000 for workplace L2 that also serve as community charging locations overnight and, on the weekend, (a unique value proposition designed to increase equitable access to charging and maximize use of charging infrastructure). Fleet also offers a long-duration direct current ("DC") rebate of up to

$15,000 per plug of 50 kW or less, focused on medium and heavy-duty vehicles such as electric school buses that have larger batteries and need a higher power level to complete their charging cycle off-peak. Although long-duration DC is at power levels higher than the typical L2, the off-peak load shapes being incentivized mirror those of the other off-peak programs as the duration of charging needed via the DC charger is still four hours or more. Finally, fleets also benefit their entire communities given their high-mileage use and corresponding reductions in local pollution (noise and environmental).

In sum, the residential, public and fleet programs form a TEP portfolio strategy to both (1) optimize the grid to benefit all customers, and (2) aid EV adoption by creating charging confidence via strategically located infrastructure and equitable access to charging. Given the data the Company has reported to the Commission,[6] the TEPs continue to serve the majority of managed charging scenarios, aid with equitable access to charging infrastructure, and achieve the intended results. The Company believes the data strongly supports continuation of the TEP programs.

Q. Are TOU rates enough to optimize off-peak charging without TEP programs?

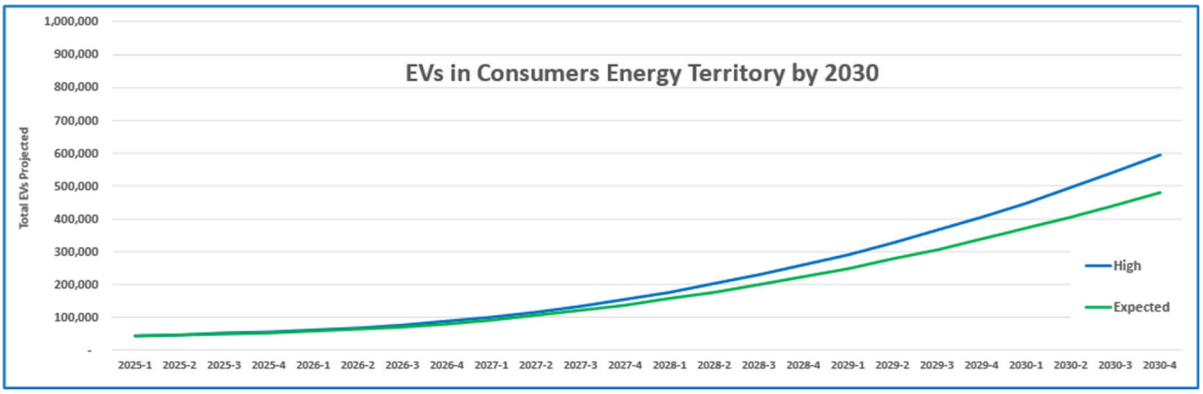
A. Absolutely not. It continues to be the case that a negligible number of EVs enroll in the Company's TOU rate without engagement. For example, in late 2023 the Company's AMI data analysis showed just 493 of the 30,380 EVs enrolled in Rate 1050 (Nighttime Savers) without TEP rebate or incentive engagement, which equates to a mere 1.6% of EV customers. Again, in late 2024, advanced metering infrastructure ("AMI") data analysis

[6] See 2024 TEP Report, at 0688y00000EFQgtAAH; see also 2023 PowerMIDrive and PowerMIFleet Annual Reports, at 0688y000008L9UaAAK and 0688y000008KyQSAA0. The original TEP strategy from 2022 was provided in 0688y000002lGMlAAM. Finally, additional reports from the pilot phases (2022-2020) leading to the TEP are also available at 0688y000003NM62AAG, 068t000000NieAVAAZ, and 068t000000D3t95AAB. All of these regulatory filings show the Company's consistent focus on optimizing the grid and increasing charging infrastructure via strategic locations to benefit customers.

indicated just 526 of 39,950 EVs enrolled in Rate 1050 without TEP program engagement, which is 1.3% of EV customers. The data is incredibly clear and irrefutable. Relying on TOU rates alone is highly ineffectual for EV load management. TEP programming must continue to optimize EV load.

Q. Are EV adoption and load growth projections continuing to materialize similar to the projections provided in prior filings?

A. Yes. EV load growth has been at or above the "500K EV" by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (Case No. U-21090), annual TEP related reports, and prior electric rate cases. While the Company continues to prepare the TEPs to optimize load for one million EVs by 2030 in support of the State's policy goals, which strongly support EV adoption and Michigan's automotive manufacturing economic strength, EVs on the road are trending slightly lower than prior projections. In 2023, an outside source projected there would be 630,000 EVs on the road by 2030, and in 2021, the Company projected there would be 500,000 EVs by 2030.



The latest data from the Michigan Secretary of State also indicates that a range closer to 470,000 to 600,000 EVs by 2030 may be more likely in the Company's territory. Whatever the correct forecast, there are more EVs on the road now than ever before and those EVs

are driving more miles per year. Plus, more EV models are entering the market (SUVs, crossovers, and trucks) that are using more kWh per mile, and the Company's electric territory continues to be a destination for many EVs that reside outside of our electric territory (e.g., the greater Chicago, Detroit, and Toledo metros). Furthermore, our electric territory is the last opportunity to charge before traveling into the Upper Peninsula. Thus, total EV load growth, which is what truly matters for margin analysis and TEP program funding, remains solidly on track as shown in Exhibit A-165 (JAM-3) (see "Cost Benefit Analysis" tab, line 22).

Q. Please describe the specific TEP enhancements proposed to improve customer experience and benefits.

A. To be clear, the Company continues to implement the TEP program enhancements approved in Case No. U-21585, is maintaining the PowerMIDrive Residential program as approved in Case No. U-21224, is maintaining the PowerMIDrive Public Charging and PowerMIFleet programs as approved in Case No. U-21389, and is completing the pilot funds dedicated to customer projects in progress per approvals in Case Nos. U-20134, U-20697, and U-21224. No increases to the TEPs budget previously approved are proposed, and no changes are being made to the core program strategies to optimize off-peak charging from these recent permanent program approvals by the MPSC.

The proposed TEP enhancements are:

(1) The allowance of the weatherized and EV-rated National Electric Manufacturers Association ("NEMA") 14-50 outlets across all L2 rebate categories and NEMA 5-20[7] outlets across all long-duration L1 rebate categories. Given that many new EVs come with, and existing EV drivers utilize, a portable charger, focusing a project on the outlet can simplify installations and reduce costs for host sites. In particular, multifamily locations

[7] NEMA 14-50 and NEMA 5-20 are standardized outlet designs commonly utilized for EV charging. Many L2 utilize a NEMA 14-50 plug for charging up to 9.6 kW, and many L1 utilize a NEMA 5-20 plug for charging up to 1.8 kW.

have expressed interest in bring-your-own-cord ("BYOC") solutions given desires to reduce costs and maintenance. Presently only community charging host sites can utilize outlets as a BYOC option, and the Company believes that it is a useful option across the board to reduce infrastructure costs.

(2) The continuation of Direct Current Fast Charging ("DCFC") rebates on a time-limited and selective basis. The Company continues to believe that DCFC infrastructure incentives are needed to better enable EV travel and to encourage EV adoption. The Company also recognizes feedback from the MPSC Staff that such incentives should work to create a skeleton network, not be a permanent program, and recognize the 30C~~D~~ tax credit impacts.[8] Thus we are modifying our fast-charging rebate proposal as follows:

a. The Company proposes a fast-charging rebate of up to $50,000 per 150 kW DCFC port. The median and average costs of a 150 kW DCFC construction project range between approximately $200,000 and $237,000.[9] The 30C~~D~~ tax credit is available for some, but not all, locations in the Company's electric service territory[10] and may provide a 30% tax credit for the project costs.[11] Thus, it is possible that the cost of a 150 kW DCFC project could be reduced to near $140,000 to $166,000 via the 30C~~D~~ tax credit, and a rebate of up to $50,000 is approximately 1/3rd of the remaining cost, consistent with the original PowerMIDrive pilot approval that collaborated with Charge Up Michigan funds (Charge Up Michigan funds are no longer available, but the 30D tax credit may be available for some locations).

b. The DCFC rebates will only be available for communities that do not have at least four 150 kW DCFC ports across two or more different host sites. The four 150 kW ports per community is proposed as a cutoff because that mirrors the Federal minimum (i.e., skeleton) infrastructure per NEVI Standards and Requirements. See 23 CFR § 680.106(b). However, if those four ports are not spread over two or more different host sites in a community, then competition is limited, and thus an additional site will help keep pricing reasonable. Anecdotally, the Company has noticed that DCFC charging prices come down when a second host-site opens in an area. Thus, these criteria will steer rebate eligibility into communities that do not have fast-charging infrastructure and avoid subsidizing additional builds in urban areas that already have infrastructure.

[8] See MPSC Case No. U-21585, Staff's Reply Brief, pages 26-28, at 068cs00000Rc1jfAAB.
[9] See 2024 TEP Report, pages 28 and 29, Figures 5 and 6, at 0688y00000EFQgtAAH (Median construction costs of $168,654 and make-ready costs of $30,608 total $199,262, while average construction costs of $191,239 and make-ready costs of $45,509 total $236,748).
[10] See the 30C Tax Credit Eligibility Locator for a map of eligible locations. Some areas were only eligible in the past or will drop off in future years.
[11] United States Department of Energy, Alternative Fuels Data Center: Alternative Fuel Infrastructure Tax Credit (last visited April 28, 2025).

c. The DCFC rebate application will only be available for two-years after approval by the Commission. Thus, the fast-charging rebate program proposed is not a permanent offering. However, please note that host sites will be awarded their rebate after construction is complete, which will take longer than the two-year window for rebate applications. Nonetheless, if approved by the Commission, the limited DCFC rebate offering will be contained within the TEP budget already projected and approved, and the Company may close applications if the TEP budget is at risk of being exceeded.

d. The Company will review rebates as they are received, thereby encouraging expedited development of the skeleton network, but retains the right to reject applications that do not offer quality customer experience. Given the competitive nature instilled by the limited TEP budget, and the proposed time and location restrictions for applications, the Company proposes the following criteria to guide DCFC rebate host site selection and aid EV adoption by improving the customer experience:

1. The host site should offer 24-7 charging and amenities, such as restrooms, snacks, and meal opportunities for an average dwell time of approximately 30 minutes. If such amenities are not 24-7, then preference will be given to sites with longer operating hours and a greater number of such amenities at or adjacent to the site. In no case shall sites be allowed that do not offer 24-7 charging or that have no public amenities. Furthermore, chargers and companies that cannot maintain the existing DCFC performance requirement of 97% uptime may also be excluded from future rebates if good faith efforts to restore uptime cannot be demonstrated.

2. The host site should install the fast chargers within view of the road and with pricing signage. Drivers need to see and be able to find fast charging infrastructure. Preference will be given to such sites over those that are at the far edge of a parking lot or hidden to the side or behind a building or other visual obstacle.

3. The host site should utilize fast charging dispensers that can be activated with a credit card or phone tap to pay instead of a specific app. The use of multiple apps can be confusing, is a barrier to adoption, and also slows down throughput at a site if a customer does not already have the app installed and activated. Preference will be given to host sites that replicate the experience of "pay at the pump" that many consumers are used to.

4. The host site must have adequate security lighting and preferably a canopy to protect from the weather. Drivers need to feel safe while charging at night, and fast charging equipment is less likely to be damaged by vandalism or exposure to the elements at such sites. Thus,

preference will be given to host sites that offer good lighting and a canopy.

5. The host site should use traffic flow designs to accommodate the multiple charge port locations of various EV models, larger EVs, and EVs pulling trailers. Preference will be given to sites that utilize pull-through or other layouts that maximize access for different EV types and sizes.

6. More traffic lanes, more ports. While more remote communities on two-lane highways still greatly benefit from the addition of two 150 kW fast charging ports at a host-site, locations near four-lane highways or that experience high seasonal tourist inflows would benefit from more ports. Thus, all host sites must offer at least two 150 kW DCFC ports, and preference will be given to sites with more fast-charging infrastructure, to increase charging confidence by EV drivers. However, no more than four rebates will be offered per host-site in any case.

In sum, the Company believes that the above enhancements will reduce construction costs for the existing L2 and L1 program rebate categories, and temporarily expand rebate offerings to help create a skeleton network of quality fast-charging sites in areas that are still underserved via a time and budget limited competitive process.

Q. Does the continued growth of EV adoption impact the testimony of another Company witness that you wish to support?

A. Yes. While many TEP programs focus on relatively low-power and longer-duration charging to minimize grid impacts, and are successfully optimizing the load from those participants, the Company anticipates that new service requests for DCFCs, both public and for fleets, will grow dramatically in larger population centers. Thus, I support Company witness Jennifer M. Partlan's request to proactively prepare for new and expanded DCFC and larger fleet locations, especially in urban and interstate locations where large developments are already occurring.

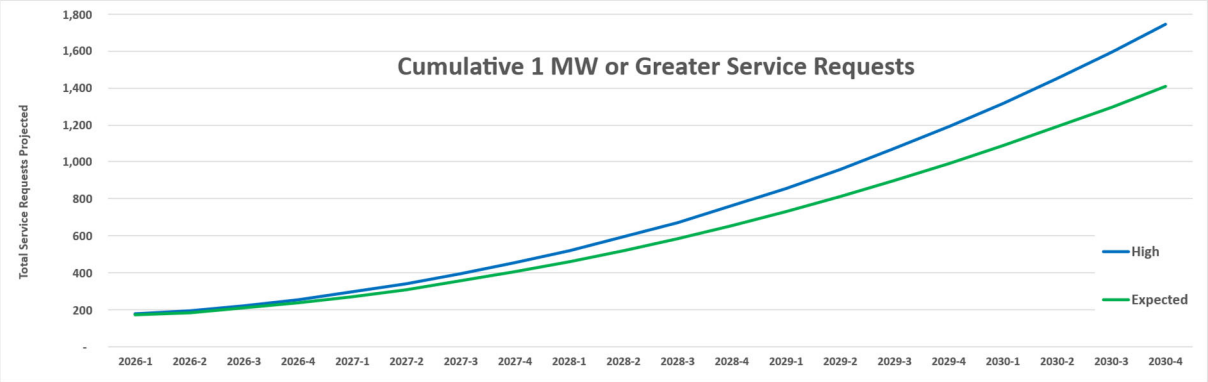
To gain perspective on the magnitude of the challenge, we must first recognize that many utilities are reporting that transformers supporting larger load sites (i.e., 500 kVA and greater) can have lead times of 18 to 24 months or longer. This means that waiting until a request for new or modified service for a fast-charging site or new fleet depot to place an order for these transformers and related equipment will bottleneck EV adoption.

Looking at trends in DCFC development, new or expanded fast charging sites near urban areas are larger and higher power, in addition to being installed at an increasing frequency. For example, market data indicates that one fast charger is constructed for approximately every 85 EVs on the road. Furthermore, developers are considering additional capacity for holidays and cold weather impacts. More fast-charging sites are also being installed with at least four chargers each of 250 kW or higher ratings, and thus potentially drawing up to 1 MW at maximum output. The reason for this is the capabilities of new EVs can often reach higher charging inputs, and customers prefer to choose a fast-charging destination with multiple chargers and higher power outputs to avoid the risk of queuing or impacts from a plug being down for maintenance.

Thus, many urban fast-charging sites are now trending toward sets of 8-12 fast chargers, and we have learned of potential plans for 40 or more chargers along interstate travel corridors. Furthermore, delivery fleets may desire to add hundreds of new EVs per year as their current vehicles age out, and even with L2 charging this can result in large load additions given the scale. These are very important trends to prepare for given continued EV adoption and ensuring Michigan businesses and residents are timely served.

As a planning estimate, utilizing the ratio of one 250 kW fast charger per every 85 EVs, and growth rates trending between 470,000 and 600,000 EVs by 2030, the

Company projects that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the near two-year timeframe to design a new service, procure and install make ready equipment, and energize a site, it is prudent to act now in preparation for forthcoming EV service requests.



Q. In the Company's Case No. U-21585 the Commission ordered the Company to provide updates on approved enhancements and any lessons learned in the Company's next Electric Rate case and PowerMIDrive and PowerMIFleet annual report, as recommended by the Staff. How is this being addressed?

A. The Company ~~will be filing a~~ filed its 2025 TEP Annual Progress report in Docket No. U-~~21389~~ 21538 ~~before July 1~~ on June 27, 2025. ~~The Company incorporates the report by reference~~ I am sponsoring the report as Exhibit A-230 (JAM-6), ~~and I plan to sponsor it as an exhibit through revised direct testimony or rebuttal testimony as appropriate~~ as I indicated I would in my original pre-filed 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-21870

EXHIBIT

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

June 27, 2025

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

RE: Case No. U-21538 – In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file transportation electrification plans and for other related matters.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Transportation Electrification Plan Annual Progress Report 2025**.

This is a paperless filing and is therefore being filed only in PDF. I have included a Proof of Service showing electronic service upon all intervenors from Case No. U-21585 (Consumers Energy Company's 2024 Electric Rate Case) and all parties who filed Initial Comments or Reply Comments in Case Nos. U-21492 and U-21538.

Sincerely,

Digitally signed by Spencer A. Sattler
Date: 2025.06.27 14:39:15 -04'00'

Spencer A. Sattler
Phone: 517-474-6638
Email: spencer.sattler@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

Power MI Drive | Power MI Fleet | Consumers Energy Count on Us®

CONSUMERS ENERGY

Transportation Electrification Plan

Annual Progress Report 2025

Case No. U-21538
June 2025

Table of Contents

BACKGROUND 4
TEP EXECUTIVE SUMMARY & STRATEGY 7
TEP IMPLEMENTATION 12
TEP CUSTOMER PARTICIPATION & COSTS 28
TEP MANAGED CHARGING RESULTS 43
TEP LOOKING FORWARD & STAKEHOLDER FEEDBACK 46

Digital residential customer campaign sample

Table of Figures

Figure 1: Residential Customer Costs of Home Charger & Installation 28
Figure 2: Level 2 Site Host Category Participation (Pilot + Permanent Program) 30
Figure 3: Public L2 Site Project Costs Per Dual-Cord L2 31
Figure 4: Public Level 2 Sites by Location & Type 32
Figure 5: DCFC Site Project Costs 33
Figure 6: DCFC Site Make Ready Costs 34
Figure 7: Fast Charging Locations 35
Figure 8: PowerMIFleet Assessments by Customer Sector 36
Figure 9: In-Person Customer Education & Outreach Locations Overlaid on MIEJ Screen Map 40
Figure 10: EV Charging per Category & Time Block 43

Kids Food Basket and the Consumers Energy EV team celebrate the delivery of their new electric van to deliver nourishing meals to kids in need.

BACKGROUND[1]

Consumers Energy (Consumers Energy, CE, or the Company) began the first phase of creating the Company's Transportation Electrification Plan (TEP) via the PowerMIDrive pilot, which was approved by the Michigan Public Service Commission (MPSC) in Case No U-20134. PowerMIDrive subsequently launched in June of 2019, with a goal of at least 70% off-peak load management for residential customers, and to provide early learnings regarding public charging infrastructure. The Company's TEP formation was further enhanced via the addition of the PowerMIFleet pilot approved in Case No U-20697, and efforts to optimize electric loads from fleets to at least 80% off-peak began in June 2021. The Company believed that the higher level of off-peak charging was possible for PowerMIFleet based on the learnings and promising early results of PowerMIDrive.

The PowerMIDrive and PowerMIFleet pilots were further refined in Case No U-20963, with the goal of moving closer to permanent programs. PowerMIDrive added the use of advanced metering infrastructure (AMI) for targeted outreach and load management verification. Furthermore, PowerMIDrive shifted the focus of public Level 2 (L2) charging infrastructure to destination charging to increase off-peak loads, and multi-dwelling units (MDUs) to enhance customer access and equity. PowerMIFleet added capital funds for fleets serving income qualified customers and disadvantaged communities, again to improve customer equity regarding transportation electrification. These enhancements were approved by the Commission in December 2021.

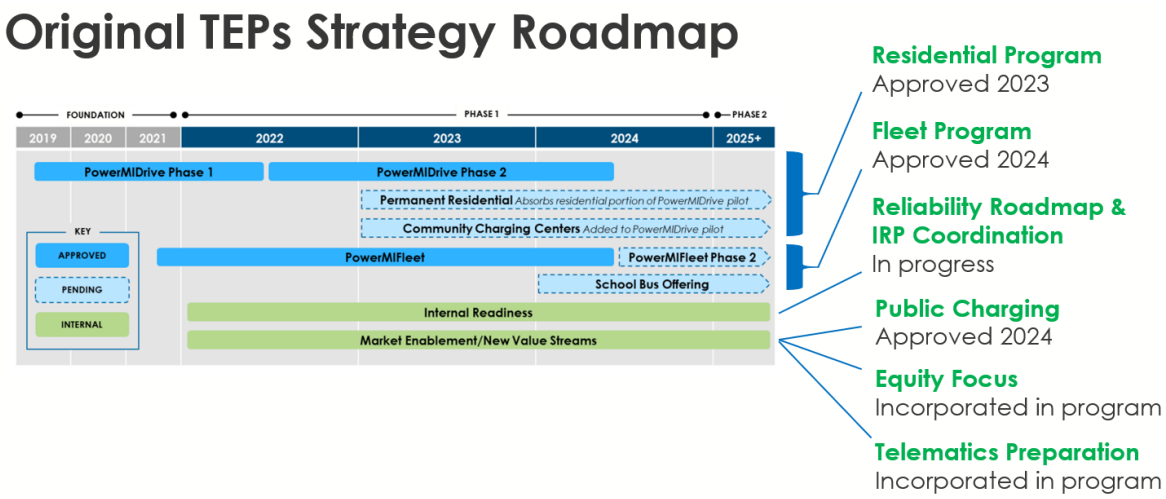
The first official TEP filing (under the heading of "Consumers Energy 2022-2030 Transportation Electrification Strategic Plan") was included in Case No U-21224. In January 2023, the Commission approved the Company's proposal to make the PowerMIDrive Residential program permanent, including the MDU component, and to add community charging rebates to the PowerMIDrive public infrastructure pilot. The community charging pilot was proposed by the Company to further increase equitable access to off-peak charging by customers.

Finally, in Case No U-21389, the Company proposed making both PowerMIFleet and the PowerMIDrive Public programs permanent based on the continued pilot refinements and learnings of the past four years. In March of 2024, the PowerMIDrive Residential, PowerMIDrive

[1] See 0688y00000EFQgtAAH for the Company's 2024 TEP report. See 0688y000008L9UaAAK and 0688y000008KyQSAA0 for the 2023 PowerMIDrive and PowerMIFleet annual reports. The original TEP strategy from 2022 was provided in 0688y000002lGMlAAM. Finally, additional reports from the pilot phases (2022-2020) leading to the TEP are also available at 0688y000003NM62AAG, 068t000000NieAVAAZ, and 068t000000D3t95AAB. All of these regulatory filings show the Company's consistent focus on optimizing the grid and increasing charging infrastructure via strategic locations to benefit customers.

Public, and PowerMIFleet programs were authorized by the Commission, creating the first comprehensive utility EV load management program approved without legislative mandates.

The goals laid out in the original TEP filing were achieved, as summarized in the graphic below excerpted from the original TEP filing.[2]



The strategic roadmap objectives in the Company's first TEP have all been approved and focus on equitable charging access such as the up to $1,000 income-qualified residential rebate, multifamily rebates, community charging rebates, and workplace charging rebates, in addition to PowerMIFleet's strategic focus on fleets serving income qualified and disadvantaged communities, non-profits, educational institutions, government agencies, and small and medium businesses.

Telematic preparation is also being achieved given the Company's focus on Level 2 charging, in addition to some long-duration direct current (DC) and Level 1 rebates, by focusing on key market segments that are likely to be off-peak. All of these use cases focus on situations providing 3 hours or more of plug-in time where telematics can be meaningfully engaged in the future.

In 2026 the Company will file an updated TEP, and annual reports thereafter will utilize the TEP reporting requirements published by the MPSC. This is the last annual update utilizing the format developed during the pilot phase of our TEP programs.

[2]See page 19 of Exhibit A-152 (JAM) in Case No. U-21224, which is page 2937 of 2942 in the PDF: 0688y000002IGMIAAM (site.com)

Consumers Energy's TEP programming was featured at the anchoring panel of the 2024 Peak Load Management Alliance EV Summit

Consumers Energy's TEP programming was recognized by EPRI for contributions in planning for millions of EVs on the road

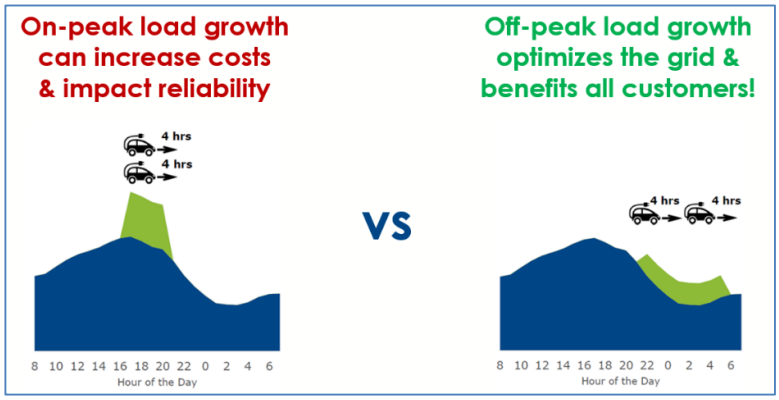
TEP EXECUTIVE SUMMARY & STRATEGY

Governor Whitmer and the State of Michigan have set a goal of two million EVs in Michigan by 2030, and in support of Michigan's goal and the size of the electric territory the Company serves, Consumers Energy set an ambition to be ready to serve one million of those EVs. The Company' s TEP is the strategic document that roadmaps how serving one million EVs (and more beyond 2030) will be achieved. Supporting the TEP are three essential customer load management programs (PowerMIDrive Residential, PowerMIDrive Public Charging, and PowerMIFleet), in collaboration with coordinated planning via the Company's reliability road map and integrated resource plan (IRP). All these TEPs elements are critical to meeting the goals while optimizing EV charging to the benefit of all customers.

Within this context, the Company's' TEP is focused on three primary strategies:

1) Load growth at the right time to benefit reliability and cost for all customers

Not all customers are EV drivers, but the goal of the Company's TEP continues to be that all customers should benefit from the EV programs by maximizing off-peak charging.



On-peak charging can dramatically increase distribution system needs at the service and distribution circuit transformer level. For example, most residential loads peak at near 10 kW, and even L2 charging can double that on a 50-amp circuit (an additional 9.6 kW), or potentially even triple such peak loads if multiple EVs in a household are charging or a more powerful 100-amp circuit L2 is utilized (an additional 19.2 kW). Given the growth trends of EVs, it is easy to imagine how reliability concerns and infrastructure replacement could occur near the grid edge with distribution infrastructure that was constructed to serve customers in a pre-EV era.

Without EV load management programs, most customers will pay no attention to on-peak time periods (presently 2 PM to 7 PM weekdays and likely shifting later over time as more solar generation is added to the grid) when charging. The Company knows this because in the spring of 2025 our AMI data analysis showed just 497 of the 39,950 EVs in the Company's electric territory enrolled in Rate 1050 (Nighttime Savers) without rebate and incentive engagement. That equates to a mere 1.2% of EV customers, consistent with data trends from the last several years, and thus relying on time of use (TOU) rates alone is not sufficient to incentivize residential EV load management.

Furthermore, in public settings time-of-use (TOU) rates alone for L2 infrastructure made less impact than when combined with specific use cases (e.g. destination locations like hotels) as noted in the annual reports throughout the pilot phase of PowerMIDrive, because the cost differential for charging is relatively low. This is why the PowerMIDrive Public program now exclusively focuses on TOU rates plus strategic off-peak use-case locations like workplaces for the morning hours, and community charging, multifamily, and destination charging for the overnight and weekend hours.

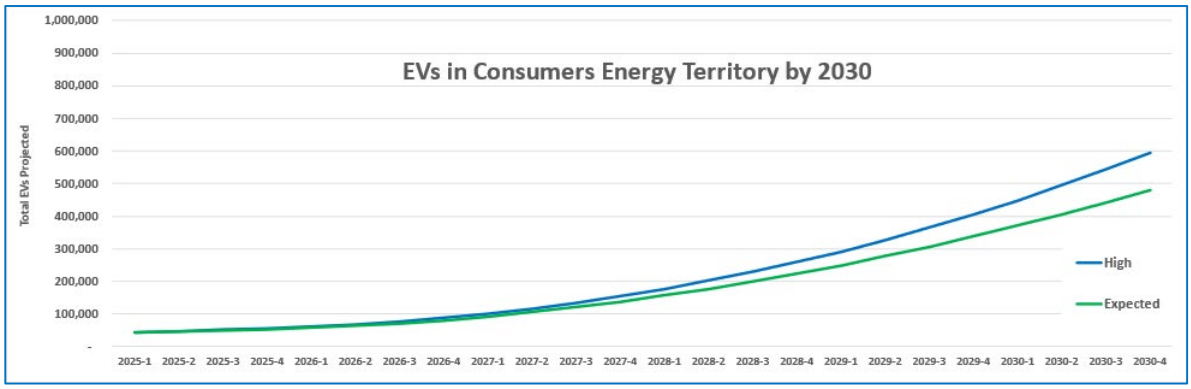
With EV load management programs more kilowatt-hours (kWh) can flow through the same infrastructure, which not only reduces reliability risks at the grid edge but also lowers costs for all customers by optimizing energy usage and infrastructure, while helping to avoid or delay local system upgrades. The off-peak charging results for all charging categories are summarized in the table below. Permanent TEP programs achieved nearly 96% off-peak charging and still maintained an impressive off-peak percentage close to 90% when direct current fast charging (DCFC) loads were included.

EV Customer Program Category	On-Peak 2PM-7PM	Off-Peak 7AM-2PM 7PM-11PM	Super Off-Peak 11PM-7AM & Weekends	Total Off-Peak by Category
Residential Single Family	*2.1%*	*6.6%*	*91.3%*	*97.9%*
Community Charging	*21.6%*	*33.8%*	*44.6%*	*78.4%*
Multifamily	*18.3%*	*35.2%*	*46.5%*	*81.7%*
Total Residential	***2.6%***	***7.4%***	***90.0%***	***97.4%***
Destination L2+L1	*20.6%*	*36.3%*	*43.1%*	*79.4%*
Fleet & Workplace	*8.9%*	*40.8%*	*50.3%*	*91.1%*
Original Pilot: DCFC	*24.5%*	*35.2%*	*40.3%*	*75.5%*
Total Commercial	***20.1%***	***36.8%***	***43.1%***	***79.9%***
Permanent Programs	***4.1%***	***13.9%***	***82.0%***	***95.9%***
Permanent & DCFC Pilot	**10.4%**	**20.5%**	**69.0%**	**89.6%**

2) Encourage and prepare for EV adoption at scale

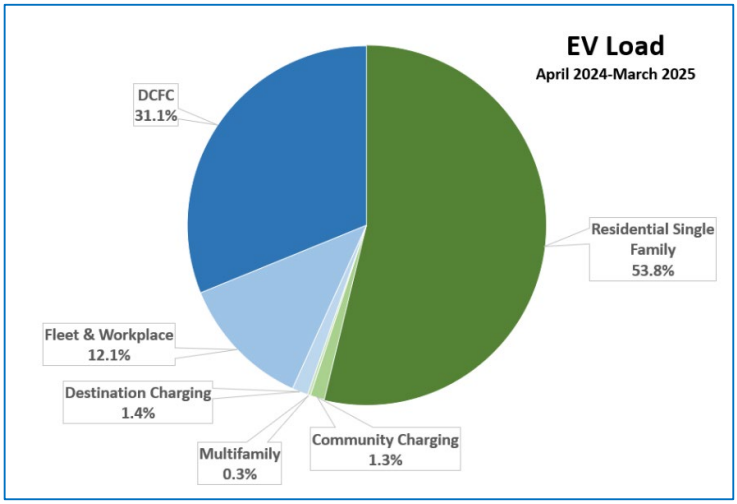
EV adoption is viral, with the most likely customers to buy or lease an EV being customers who live near someone with an EV. For example, residential distribution circuits that served three EVs near the start of the pilot may now be serving 17 or more EVs. Thus, while seasonal EV sales will vary, it is prudent to remain focused on the long term given how quickly EV adoption has been occurring and the potential for concentrated distribution level circuit impacts.

EV load growth has been at or above the "500K EV" by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (IRP), annual TEP related reports, and prior electric rate cases. While the Company continues to prepare the TEPs to optimize load for one-million EVs by 2030 in support of the State's goal, and strongly supports EV adoption and Michigan's automotive manufacturing economic strength, EVs on the road are trending slightly lower than the prior approximate range of 630K EVs (i.e. the McKinsey projection from 2023) and the Company's prior 500K EV (2021 IRP projection) by 2030.



The latest data from the Secretary of State indicates that a range closer to 600K to 470K EVs by 2030 is more likely in the Company's territory. Nonetheless, those EVs are driving more miles per year due to improving public infrastructure, more EV models are entering the market (e.g. SUVs, crossovers, and trucks) that are using more kWh per mile, and the Company's electric territory continues to be a destination for many EVs that reside outside of our electric territory (e.g. travelers from the greater Chicago, Detroit, and Toledo metros) and to enable EV travel into the upper peninsula. Thus, total EV load growth, which is what truly matters for margin analysis and TEP program funding, remains solidly on track (see the financial graphic in following subsection).

Beyond EV adoption levels, residential and commercial charging continues to proportionately evolve. The Company's latest data shows a near 55/45 split between residential charging in green, and commercial charging in blue (up from approximately 70/30 in 2024, and 80/20 in 2023). The larger proportion of commercial charging is driven by the rapidly growing use of public fast charging (DCFC) as customers drive their EVs longer distances to enjoy the abundance of tourist destinations in our electric territory.



Near term, the Company believes that additional incentives are still needed to bring fast-charging infrastructure to more rural and underserved communities and has proposed a limited window of funding for a $50,000 rebate per 150 kW port, in communities where four such ports do not exist across at least two different host sites. Knowing that a fast-charging site exists within your community is important to spur continued EV adoption via charging confidence, while also enabling travel to and

through those communities by visitors. The rapid growth in fast charging clearly indicates that the infrastructure is valued and utilized by customers in the areas served.

As a planning estimate, utilizing the ratio of one 250 kW fast charger per every 85 EVs, and adoption trending between 470K and 600K EVs by 2030, the Company projects that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the near two-year timeframe to design a new service, procure and install make-ready equipment, and energize a site, we are taking prudent action now in preparation for forthcoming EV service requests by collaborating with our supply chain and low voltage distribution planning teams. We also encourage fast-charging developers and large fleet planners to proactively reach out to us to begin project specific planning, including through initiatives such as ERPI's GridFAST[3].

Circling back to the residential sector and the Company's focus on equitable access, at least one out of three residential customers may not live in a single-family home or be able to install L2 charging at their residence. The need for alternative charging locations in the future is very real, and access needs for workplace charging, community charging, and multifamily charging are expected to increase dramatically.

For example, the Company's viewpoint is that there will be a near 1-to-1 ratio of L2 chargers and light duty EVs, with approximately 2/3 of those being private at residences and fleet locations, and 1/3 of EV drivers seeking or relying on public L2. Utilizing the current EV growth rate projections, this means approximately 155,000 to 198,000 L2 plugs in equitable access and public locations may be needed in the Company's territory by 2030. Again, we believe that long-duration and equitable access locations like workplace, multifamily, community charging, and destination charging are where these L2 should be prioritized by TEP programming to optimize charging load. DCFCs support EV adoption and the continued societal benefits that come with it.

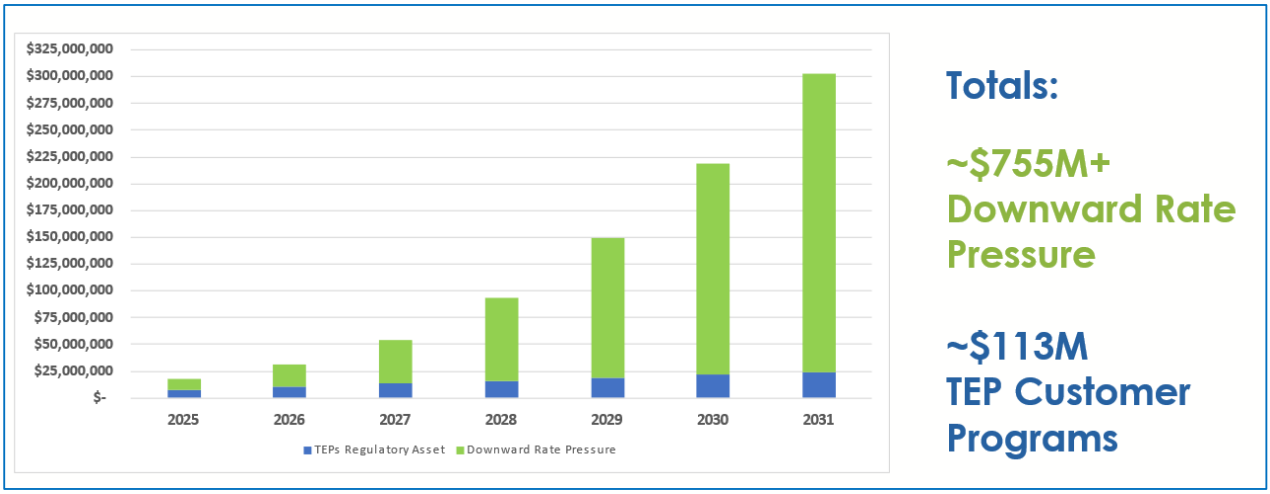
Projected Number of Plugs Needed

EVs	1,000,000	600,000	470,000
Residential Single Family L2	520,000	312,000	244,000
Equitable Access & Public L2 Multifamily, Community Charging, Workplace, Overnight Destination	330,000	198,000	155,000
Fleet L2	150,000	90,000	71,000
DCFC (1 MW sites)	11,800 (2,900)	7,100 (1,800)	5,500 (1,400)

[3]EPRI's collaborative interface can be found at: GridFAST.

3) The additional margin from EV load growth will continue to pay for EV load management programs while also creating downward rate pressure for all customers

Consumers Energy is fully convinced that EV load growth at the right time presents a unique opportunity where a portion of the additional margin from EV load growth is easily able to fund EV load management programs and accelerate charging infrastructure developments, while preserving margin for downward rate pressure benefiting all customers. In fact, utilizing the expected scenario for EV adoption, the projected investment in EV customer load management programming recovered via the regulatory asset is approximately $113 million, which is greatly outweighed by the downward rate benefit projected to be more than $755 million of remaining EV load margin between now and 2031. Thus, EV programs clearly pay for themselves and are not paid by non-EV driving customers. Moreover, all customers continue to benefit from EV load growth and continued electrification should be encouraged.



Using the three strategic principles above, Consumers Energy's TEP is focused on scaling programming and planning for key market segments in support of Michigan's EV goals. To date, even with efforts that do not include direct control, off-peak load management has achieved breakthrough results benefitting all customers. The Company's EV load management programs have achieved greater than 95% off-peak charging between April 2024 and March 2025, which is best in class for utilities and well beyond the original pilot goal of 70% off-peak charging.

The Company is also preparing for future technology developments, such as active charging management via telematics. All market segments in which active managed charging is likely to be acceptable to the customer are covered by our approved programs in the TEP. Furthermore, future technologies such as active managed charging and bidirectional power flows are not possible if a vehicle is not plugged in due to a lack of infrastructure, and our customer programs are working to optimize the likelihood of such opportunities.

TEP IMPLEMENTATION

The section below summarizes the implementation strategies taken by the Company to continue to optimize EV load growth, across all key market segments for charging, for the benefit of all customers.

Residential Single-Family Rebate & Incentives

The majority of EV charging occurs at home, and most residential EV drivers utilize L2 chargers, which can significantly impact residential peaks. Moreover, residential EV loads continue to be the largest kWh segment in the TEP. Thus, it is critical that we engage a significant proportion of residential EV drivers to maintain loads within residential design standards and optimize charging behaviors. To create an attractive load management program, Consumers Energy offers a combined offering of:

- **$500 (up to $1000 for income qualified customers) home installation rebate** for any UL, EnergyStar certified level 2 charger on a 240-volt circuit of 50 amps or less. This rebate typically covers up to half of the installation cost, thereby drawing customers in to discuss optimal rates and charging times to save money and optimize the grid.
- **$10 monthly incentive** for enrollment into the Smart Charging Incentive Program avoiding on-peak charging (over 12 months and thus $120 potential total incentive). This behavioral reinforcement over all four seasons of weather creates a gamification challenge to save and earn additional money, while also giving the customer confidence that off-peak charging is possible year-round. We continue to see customers maintain their off-peak charging after graduating from the program, which also avoids ongoing operational costs for incentives.

To be eligible for one, or both, of the rebate and incentive offers above, a customer must:

- Be a current full-service Consumers Energy electric customer
- Own, lease or have an EV on order
- Agree to enroll in a year-round TOU rate at home, with Nighttime Savers being the recommended option (Rate Code 1050)
    - Program weekday charging to occur during super off-peak timeframe (11PM-6AM) and avoid charging during on-peak times (2PM-7PM)

As Consumers Energy seeks to ensure that grid benefits are optimized while the EV market is rapidly expanding, the Company's residential program continued to analyze home EV charging patterns of participating customers. The team focused education efforts and customer awareness of the benefits a year-round TOU rate and off-peak charging can offer an EV driver (namely, approximately $1.30 per e-gallon equivalent), with an emphasis on 11 PM or later start time for charging to further assist all customers via super off-peak charging.

In 2025 we also began working with customers to voluntarily change their start time based on their daily driving habits. For example, a lower mileage driver or a plug-in hybrid owner may be willing to program their charging to start at 1AM or 2AM instead of 11PM. This helps create load diversity and decreases ramp rates at no additional cost to the program. Only a few months into this voluntary initiative, over 300 EV drivers have already modified their charging start time.

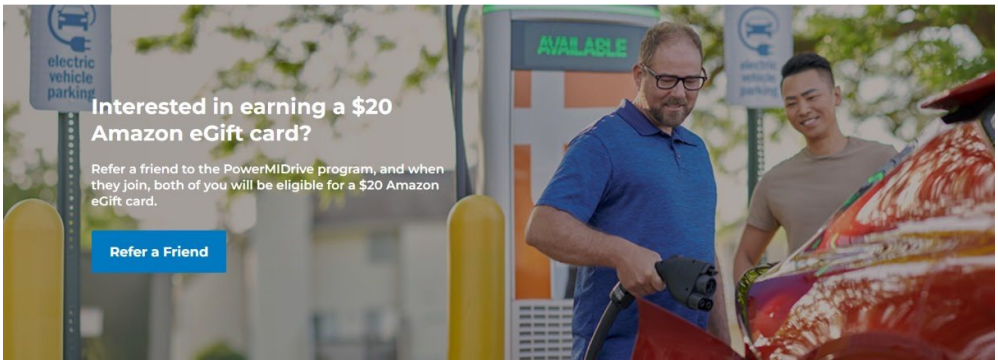
The Company continues internal collaboration with the Low Voltage Distribution Planning (LVDP) team to track residential transformers, looking for potential impacts where the electric grid supports multiple residences with home chargers. Analysis of residential participants continues to show no transformer reliability challenges from participating customer EV charging.

The fact that no residential customers that are utilizing a single 50-amp outlet have, to date, required make ready work on the Company's side of the meter is evidence supporting our 9.6 kW residential design standard for EV charging. These experiences were the basis for the decision to utilize a single National Electric Manufacturers Association (NEMA) 14-50 outlet as the residential standard in the permanent residential program.

However, we also know that the vast majority of EV drivers will continue driving EV and add more EVs to their household as their internal combustion engine (ICE) cars age out. Without further proactive strategy, such homes are likely to install additional charging circuits that could exceed residential neighborhood design standards as adoption continues to scale. To address this challenge, the team has begun work to implement the recently approved rebate of up to $500 for a UL listed dual cord L2 or splitter technology in which two or more EVs can charge from a single NEMA 14-50 outlet. This benefit also addresses ramp rates by spreading the load from multiple EVs across a greater time rather than having two L2 begin charging simultaneously (e.g. 9.6 kW charging over 4-6 hours is much better than 19.2 kW from two L2 charging over 2-3 hours).

PowerMIDrive team members test a power-sharing residential L2 that utilizes a single NEMA 14-50 outlet – a solution that reduces customer costs and gid impacts of homes with multiple EVs

Banner ad on the EV webpage for the new Referral Rewards program



Furthermore, we know that EV adoption is viral and the customers most likely to drive an EV are those who know someone with an EV. Customers in our programs also consistently report a 70 or greater net promoter score (NPS), which is incredibly high for utilities. Thus, in 2025 we also began implementation of a referral program, in which the referring customer and the referee upon enrolling in PowerMIDrive each receive a $20 gift card. This viral marketing approach helps to grow program participation and avoids email marketing clutter. In less than a month the referral program has already brought 28 potential new customers into the application process.

Regarding the popularity and efficacy of residential program participation, the key is the combination of rebates that get customers to participate in off-peak charging and an AMI-based incentive that positively reinforces off-peak charging behavior through all four seasons. The PowerMIDrive Residential strategies continue to show world class results, with single-family homes charging at 95% or greater off-peak and no system issues with over 8,200 EVs in the program. Rebates and behavioral incentives are providing the results needed to optimize residential EV charging as the sector continues to grow rapidly.

Sample of email communication sent to customers with AMI data indicating a high likelihood of EV ownership

Multifamily Property L2 Rebates

Approximately one of three Consumers Energy customers call a multifamily property home, and our TEP includes customer programming to ensure equitable access to off-peak charging for these residents. Multifamily properties with five or more residences typically do not have access to or the ability to install a private-use L2 for their EVs like single-family residents can. Without onsite or nearby L2 charging options, multifamily customers are more likely to rely on fast charging, which is usually similar in cost to gasoline and thus less likely to result in cost savings from driving EV. Thus, PowerMIDrive's multifamily charging rebate component is designed to incentivize multifamily property owners to invest in EV charging as an amenity for residential tenants.

PowerMIDrive Multifamily Property Charging in Wyoming, MI

In 2023, Consumers Energy launched multifamily property charger rebates as a permanent program offering. To ensure optimal grid benefits are achieved, the program provides a $7,500 rebate for at least two L2 charge ports on a maximum 100-amp circuit, thereby keeping EV charging loads similar to our single-family program. The chargers are required to be separately metered and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours. To further encourage off-peak charging at multifamily properties, PowerMIDrive provides signage and educational materials to the property, and site hosts receive a $20/monthly bill credit for the first 12 months the chargers are installed if 80% or greater of charging avoids the peak window of 2pm-7pm Monday through Friday.

As of April 2025, a total of 48 L2 rebates have been paid to multifamily properties across Michigan. Of this total, 23 rebates were paid during the original and extended pilot offering, 23 rebates were paid under the under the permanent program offering, and 2 rebates were paid as part of our Enel X swap-out efforts.[4] An additional 54 rebates are committed to 26 MDU locations around the state for in-progress projects, illustrating rapid growth and interest in the program.

We are happy to report that nearly all multifamily property participants under the permanent program have achieved at least 80% off-peak charging each month since installation was completed. Only one site host exceeded the on-peak charging limit in a single month, and with coaching from the EV team there have been no recurrences.

[4] In the Fall of 2024, Enel X abruptly announced their exit from the U.S. market, which would have rendered commercial L2 unfunctional. Thus, PowerMIDrive assisted pilot program participants who were required to use this vendor to update the L2 and maintain equitable customer access.

Community Charging L2 Rebates

Sometimes it is not economically feasible to install L2 overnight charging within multifamily residences, or for low-income communities to install at-home charging within a single-family residence. In such cases, community charging can offer a viable alternative if located near such properties where overnight and weekend parking is permitted. Thus, PowerMIDrive's community charging rebate is designed to encourage municipalities and business customers to invest in L2 charging for their communities in public parking or curbside locations that are within 1-3 walkable blocks of a multifamily property or underserved residential neighborhood. The goal of this program offering is to further support equitable access to charging for multifamily residents and members of the community without access to home charging for their electric vehicles.

To ensure optimal grid benefits are achieved, the $7,500 rebate provides several eligible installation options, including at least two L2 charge ports on a 100-amp circuit or less. Alternatively, as a bring your own charger option, two NEMA 14-50 outlets designed for outdoor continuous use, or at least five L1 charge ports, are allowed if installed on a maximum 100-amp circuit. Thus, our community charging program allows for a bring-your-own-cord (BYOC) approach that other program categories have also expressed interest in for cost-savings. The chargers must be separately metered and enrolled on CE's commercial TOU rate to encourage off-peak charging when the cost of electricity is lower.

As of April 2025, a total of 76 community charging rebates have been paid to community charging locations around the state. This total includes 43 rebates classified as community charging from the original public L2 pilot, 12 rebates paid for the community charging pilot, and 21 rebates paid as part of the Enel X swap initiative. Currently, an additional 40 rebates are committed to 16 community site hosts for projects in progress, illustrating strong growth potential as many more communities need charging access.

Community Charging in Mt. Pleasant serves nearby apartments and student campus housing

Destination L2 & L1 Rebates

Consumers Energy's electric territory covers the majority of Michigan's lower peninsula, and many popular tourist destinations for Michiganders and tourists coming from out-of-state. Thus, PowerMIDrive's destination L2 and L1 charging 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. Lower power destination charging also helps supplement fast charger locations that can see significant increases during specific seasons and holidays.

To ensure that optimal grid benefits are achieved, the permanent program provides a $7,500 rebate for at least two L2 charge ports on a circuit of 100-amps or less. At destinations where travelers are likely to park their EV for 48 hours or longer, host sites can also receive a $7,500 rebate per five level one (L1) charge ports on a 100-amp circuit.

The value of L1 charging is often overlooked, but at long term parking locations like airports and harbors, it can serve a multitude of EVs while avoiding idling challenges from L2s that usually finish charging in less than 8 hours and tie up that plug for the next 40 hours or more. Our first long-duration L1 locations are anticipated to be installed later this year.

PowerMIDrive Destination Charging at a hotel in Spring Lake

A separate meter for the chargers will be required and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours. Similar to our efforts during the pilot phase, participants will be educated on the benefits of encouraging destination guests to charge during the off-peak and weekend hours. Participants will maintain their ability to set pricing and accessibility to reflect their individual business needs.

To date, including the pilot phase and Enel X swaps, 117 destination L2 rebates have been awarded to host sites statewide. This rebate category is increasing in popularity, with multiple locations in the rebate queue for completion in the next 12 months.

Workplace L2 Rebates

Similar to home, many people spend a large portion of their week at work. Moreover, for those without access to L2 charging at home, workplaces offer a great opportunity for charging access. We anticipate that residential and workplace charging will be the two largest targets for optimized charging going forward, as they are prime locations to spread and manage load over a longer time period that will not impact the customer.

For example, the typical commute is often 40 miles or less, meaning that L2 charging can be complete well before the current afternoon on-peak time period, and as more solar comes online we can consider spreading that load further into the prime solar generation hours. Equity benefits also exist with workplace charging, because it can supplement, or in some cases substitute for, charging at home (be it single or multifamily) if such an installation is not possible or economically feasible for the customer. For all these reasons, workplace charging is an important market segment for Consumers Energy's TEP as we look to future load management opportunities.

Similar to the other commercial charging programs, to ensure that optimal grid benefits are achieved, the permanent program will provide a $7,500 rebate for at least two L2 charge ports on a maximum 100-amp circuit. A separate meter for the chargers will be required and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours.

However, given that some workplaces are adjacent to neighborhoods or multifamily housing, we recognized that a unique opportunity may exist that can aid equitable charging access. Thus, if the participating workplace agrees to allow access, and meets qualifications to serve as a community charging location (i.e., located within 1-3 walkable blocks of a multifamily property or underserved residential neighborhood), the rebate amount per two L2 chargers will increase from $7,500 to up to $10,000. In such cases, the workplace may choose to mandate specific overnight and weekend charging hours for the public, so as not to interfere with employee access to the charging stations during their work shifts.

PowerMIFleet combined Workplace & Community Charging in Flint

To date, 174 workplace rebates for L2 charging have been granted, which includes sites classified as workplace from the original PowerMIDrive pilot, Enel X

swaps, and PowerMIFleet pilot phase leading up to the permanent program. One site host in Flint has received the enhanced workplace plus community charging rebate to date, and additional sites are considering this arrangement in their plans. Currently, an additional 60 rebates are committed to 27 workplace locations for projects in progress around the state.

The load from workplace charging is included in the results for fleets via the PowerMIFleet program and continues to trend upwards with encouraging results. Presently we are achieving over 91% off-peak charging across workplace and fleet.

Workplace charging at Jackson College serves employees & commuting students

PowerMIFleet Rebates and Assessments

In the transportation sector, fleets tend to drive the most miles and thereby produce proportionately more emissions compared to other ICE vehicles. Thus, when fleets switch to electric, they can achieve outsized emissions reductions by proportionately more kWh per EV than a typical residential driver. Nonetheless, this transition is not easy given the technical challenges of switching to a new fuel type, especially for fleets with fewer resources such as those serving in public transport, education, government, non-profit, and small to medium sized businesses. Given this challenge, and the large number of people served by these fleets, the PowerMIFleet program was created to focus on helping those sectors reduce operating costs, eliminate emissions, and optimize the grid, to produce benefits for everyone.

Under the permanent program offering, with rebates as follows:

- $7,500 per two L2 charge ports
- $15,000 per long-duration DC charger of 50kW or less (mirroring L2 load shapes, but at a higher power to account for larger batteries within some fleets)

Like other customer programs within the TEP, chargers installed and rebated through PowerMIFleet must be separately metered and enrolled on the commercial TOU rate to encourage off-peak charging. A total of 137 L2 rebates and 11 long-duration DC rebates have been awarded to date, supporting 240 electric vehicles deployed to fleet organizations serving people across our electric territory.

Furthermore, when needed to help overcome technical challenges and ensure that the right EVs are utilized in the optimal use cases, PowerMIFleet has continued to partner with two fleet electrification assessment consultants to provide a customized, full-service assessment report to selected participants. As of March 31, 2025, a total of 61 fleet assessments have been completed with an additional four customer fleet assessments in progress. Anonymized assessments are then published on the PowerMIFleet website.

Going forward, PowerMIFleet will seek to partner with the customer sectors that will benefit most from a fleet electrification assessment, transitioning over time from light-duty to newer and more novel use cases for medium and heavy-duty EVs, as well as off-road, marine, and potentially aviation use cases. Thus, the frequency of fleet assessments is likely to decrease, but they remain a useful tool especially for organizations seeking supplemental grant funding.

To date, PowerMIFleet continues to trend upward achieving off-peak results of greater than 91%.

The Rapid Transit has begun the electric fleet transition by deploying 12 Ford E-Transit Vans

PowerMIFleet Electric School Bus Ribbon Cutting Ceremony with Jackson Public Schools and Highland Fleets

Jackson Public Schools deployed 21 electric school buses, the largest school bus project to date with PowerMIFleet

PowerMIFleet Enhanced Rebates for Income Qualified Fleets

As part of the pilot phase of PowerMIFleet, Consumers Energy received a one-time fund of $1.6M to support fleet electrification for organizations whose vehicle fleet serves an income-qualified community. As of April 2025, the EV team identified a total of 12 service organizations to support via enhanced rebates, with planning for additional outreach underway. Organizations include Dial-A-Ride organizations with Rides to Wellness programs for senior citizens and veterans, rural and urban school districts, and non-profit organizations who deliver meals to children in impoverished communities around the state. To date, ten organizations have deployed their new electric fleet vehicles, and the remaining two organizations are in the process of coordination vehicle delivery and driver training with our partner organization, Hoekstra Transportation.

We would like to thank the MPSC for their support in allowing us to provide this funding to worthwhile organizations around the state, connecting members of the community with emissions-free transportation, reducing operational costs via electrification, and providing the experience of riding and driving an electric vehicle from Michigan OEMs. The enhanced rebate funding via the $1.6M has been transformational for these agencies and non-profits in addition to the income-qualified communities they serve.

For example, Otsego County Food Pantry received a Ford E-Transit Cargo Van and L2 charger to support their food delivery and community services around the region. A ribbon cutting and food drive event to "jam the van" was celebrated in April 2025. Otsego County Food Pantry staff stated, "We are so excited, grateful, overwhelmed and amazed! Thank you, Consumers Energy!"

PowerMIFleet Income Qualified Community Fleet Vehicle in Gaylord made possible by the enhanced rebate program

Given the success of PowerMIFleet at optimizing the grid, less make-ready has been needed to date for the pilot phase projects still in the works. Thus, in the 2024 electric rate case the Company proposed utilizing any remaining make ready funds for additional income qualified fleet projects. The MPSC approved that request in early 2025 and the team is now working to deploy approximately $3M in additional enhanced rebates for fleets serving income-qualified customers. We are excited to see the collaborative projects that are in the works for deployment later this year and into 2026!

PowerMIFleet partnered with Grand Rapids to deploy a car share program helping income-qualified customers

L2 charging infrastructure being installed for Kids Food Basket and made possible via the enhanced rebates for income-qualified fleets

DCFC Rebate Pilot

PowerMIDrive's DCFC rebate component is presently a continuation of customer projects underway from the pilot phase of the Company's EV initiatives as we work to wrap up the 137 fast charging projects awarded. The DCFC rebates were designed to help create the start of a network of fast charging infrastructure, primarily along four-lane highways throughout the Company's electric service territory. However, much work remains to bring fast charging access to more of our rural and seasonal travel communities in support of customer travel and tourism impacts.

By incentivizing initial investment in DCFC infrastructure along such major expressways and travel corridors, benefits are already being realized by the broader community of EV drivers traveling within the state of Michigan. Convenient fast charging is a significant factor in ensuring EVs meet the needs of customers on longer-distance travel, and thus for EV adoption as well since consumers expect to be able to road-trip with their vehicle.

DCFC site hosts participating in the PowerMIDrive pilot are educated on the benefits of providing fast chargers to attract more traffic to their respective locations and supporting Michigan's economic development as our OEMs continue to electrify their vehicle offerings. Like public L2 sites, DCFC site hosts also maintain the ability to set pricing to reflect individual on-site needs. However, unlike public L2 locations, all DCFC rebate recipients implement a fee for charging and fast charging is usually more expensive per kWh than L2s that implement a fee.

The Company is pleased to report that a total of 88 of the 137 PowerMIDrive DCFC pilot sites are now operational across CE's territory to date. Of the remaining sites in progress, 24 are National Electric Vehicle Infrastructure (NEVI) sites focused on expanding fast charging to every 50 miles along major four-lane highways, and 25 sites have been selected by our team to help increase fast charging infrastructure in remaining areas. When the pilot is complete, the 137 fast charging rebates represent an important initial step toward the more than 1,400 fast charging locations projected to be needed by 2030. In particular, we believe that rural and seasonal travel communities still need incentive support to ensure the skeleton network of fast chargers is sufficient to support rapidly growing EV adoption.

PowerMIDrive partnered with GM Energy and Pilot Flying J to provide fast charging in Saginaw

Future Proofing at DCFC Pilot Sites

To help ensure the DCFC infrastructure installed allows for scalability with future EV growth and avoid rework such as replacing relatively new transformers during future upgrades, the PowerMIDrive Program was approved with approximately $40,000 in make ready budget per DCFC rebate in the pilot. These funds are designated to utility side upgrades such as transformers and line upgrades serving the host site.

PowerMIDrive Fast Charging Rebate Site in Glennie

The cost and scope of electrical upgrades at DCFC sites are evaluated with the specification to double the minimum required initial output capacity of 150 kW in aggregate per site. Thus, a 300 kVA transformer will continue to be installed at each non-NEVI DCFC site participating in the PowerMIDrive pilot as part of the electrical upgrade work performed by the Company.

As with the Company's previous TEP partnership with the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on Charge Up Michigan program funding for DCFC sites, Consumers Energy has developed a close collaborative partnership with Michigan Department of Transportation (MDOT), as Federal NEVI funding awards were announced earlier this year. Of the total 41 NEVI site awards announced across Michigan, 24 of those awards fall in the Company's electric service territory and we have worked hard to ensure that all NEVI sites can be quickly completed after NEVI contracts are finalized.

PowerMIDrive Fast Charging Rebate Site at Birch Run

We are pleased to report that all 24 NEVI sites have completed the design phase in strong support of the State goals. These sites are ready to kick off construction as soon as contracts have been executed between MDOT and the site hosts.

As each NEVI site will require four 150kW DCFC stations, make-ready infrastructure is being designed accordingly, with a 750 kVA transformer planned at each location. We are prepared to complete these projects by end of 2025 but realistically anticipate that some will be completed in 2026 due to customer schedules.

Customer Education & Outreach

With EVs rapidly growing in the early adopter phase, customer outreach and education remain a key component of the Company TEP. We know that education alone is not enough, and pairing outreach with customer programs is necessary to create opportunities for engagement about EV load and cost optimization. Thus, a multi-faceted strategy continues to be implemented to raise awareness about how off-peak charging benefits both EV and non-EV customers, the cost savings achievable utilizing TOU rates, and the public EV charging infrastructure made possible in part by PowerMIDrive.

The program team utilizes both in-person and digital channels to reach customers, raise awareness of the rebate programs, and achieve program enrollment targets, including:

- Participation in National Drive Electric Week events (September-October)
- Participation in Drive Electric Earth Month events (April)
- Trade and auto shows
- EV101 presentations at community and business organizations
- Email and direct mail outreach campaigns and newsletters
- Press releases and earned media
- Social media posts and digital media advertisements including search terms
- Radio and TV interviews
- EV-focused virtual events, conferences and panels
- Government and trade association engagement

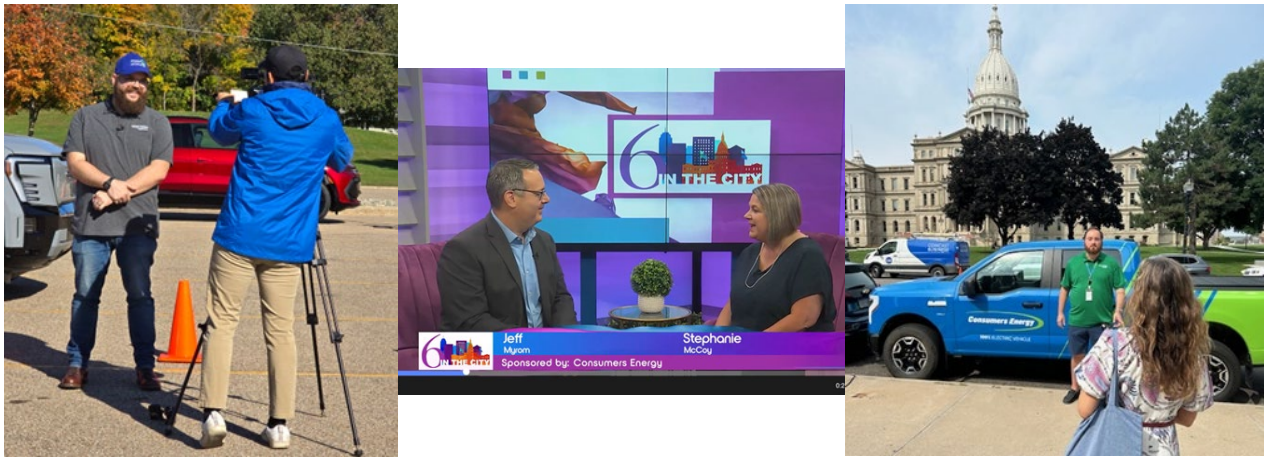
The combination of marketing and outreach lead to over 79,662 unique visitors to the PowerMIDrive residential website where customers can learn more information online, contact an EV specialist or complete their application.

The Company's EV team, which is dedicated to leading PowerMIDrive and PowerMIFleet, reaches tens of thousands of customers each year via these efforts. Team members include the following:

- Director of Customer Transportation Electrification Planning – Jeff Myrom
- PowerMIDrive Public and PowerMIFleet Program Manager – Bethany Tabor
- PowerMIDrive Public Team Members – Doug Reid, Paul Nicklowitz, and Scott Zenner
- PowerMIFleet Team Members – Steven Harris, Jenna Brown, and Kristi Baker
- PowerMIDrive Residential Program Manager – Brittany Fischer
- PowerMIDrive Residential Team Members – Stacey Walkowe, Maria Mejias, Justin Stowe, Nicolas Hutchens, and Jarrod Skogen
- Community Outreach Coordinator – Justin Stowe
- Education & Outreach Support – Therese Vainner and Brett Porterfield
- Media & Press Coordination – Brian Wheeler

PowerMIDrive & PowerMIFleet team members spoke with hundreds of customers at the 2025 auto show in Grand Rapids

PowerMIDrive team answering questions at an EV Summer Meetup in Muskegon



Media interviews get the word out to customers regarding our EV programs

TEP CUSTOMER PARTICIPATION & COSTS

Residential Single Family

As of March 31, 2025, PowerMIDrive Residential had over 7,933 EV customers, including 13 income qualified rebates in the program. These customers are participating through the up to $500 rebate (up to $1,000 for income qualified customers), the Smart Charging Incentive (i.e. $10 per month of charging super off-peak for 12 months), or both.

As part of the rebate process, the program collects residential applicant documentation to validate proof of purchase and installation of an eligible Level 2 home charger. While not all participants share their cost information or may have only part of the costs documented, these findings provide valuable insight into residential L2 retrofit costs. It also highlights the need for EV ready building codes since significant cost savings are possible during the construction process, and much of the housing stock does not have a NEMA 14-50 outlet in the parking area. Based on the program participant documentation received as of March 31, 2025, the average, high and low residential customer costs are outlined in Figure 1 below.

	Median Cost	Average Cost
Charger Only	$477	$502
Installation Included	$1,125	$1,363

Figure 1: Residential Customer Costs of Home Charger & Installation

Some residential participants did not require an electrical contractor for installation at their home because they were existing EV owners (i.e., a benefit of having a 240V outlet already in their garage), and therefore only provided cost documentation to verify proof of charger purchase. Project costs for these customers are captured in the "*Charger Only*" cost line item in Figure 1.

In cases where installation was required and an electrical contractor invoice was provided, the total out-of-pocket costs were significantly higher, as outlined in the "Installation Included" cost line item in Figure 1. Furthermore, the Company has received numerous inquiries from customers seeking general guidance on the scope of work required to install a Level 2 charger at home or looking for a referral to local electricians experienced with home charging station installations in their area. Based on this feedback, CE enhanced the Company's electric vehicle webpages to provide the resources such as a NEMA 14-50 outlet specifications so that customers feel more confident about charging their EV overnight at home.

Consumers Energy's insights from this data are that the standardization of a NEMA 14-50 outlet, assistance locating an electrician, and the rebate to assist with the costs of installation by a

qualified electrician is a clear benefit to customers and will help draw them into participating with the Company's permanent residential proposal. Moreover, the Company is now working to include power-sharing splitters and L2 chargers in the program to further improve grid impacts and customer installation costs as EV adoption continues to increase.

Allowing a rebate of up to $500 for the inclusion of home power-sharing technology incentivizes residential customers who are adding a 2nd or 3rd EV to stay within residential distribution design standards. Thus, this program strategy improves reliability for all by spreading the load over longer off-peak timeframes and reducing load ramps (e.g. two EVs charging at 9.6 kW spread over 4-6 hours on a single home circuit, instead of 19.2 kW spread over 2-3 hours). The undesirable alternative is that some customers would add a second EV charging circuit in their garage (which would not receive a rebate) not realizing the grid impact that this could have.

A power sharing splitter allows two L2 to safely utilize a single NEMA 14-50 outlet

A home charging setup for two EVs from a single NEMA 14-50 outlet offers power sharing for optimal load management as more homes adopt a second and third EV

PowerMIDrive Multifamily & Public Level 2

The program team has shifted emphasis to L2 host sites with off-peak use cases. In alignment with the Company TEP goals, this is intended to increase the proportion of off-peak charging that occurs at rebated locations, improve equity via access to charging (i.e. multifamily, community charging, workplace charging), prepare for potential active managed charging in the future via telematics, and help supplement the still limited DCFC infrastructure supporting long distance travel to destinations.

Since the launch of PowerMIDrive in 2019, a total of 415 L2 rebates have been paid to site host locations across the state of Michigan. Figure 2 below outlines the breakdown of public Level 2 site accessibility for paid rebates as of March 31, 2025.

Public Level 2 Site Host Type	Rebates Paid	% of Program Rebates (415 Total)
Multifamily	**48**	**12%**
Community Charging	**76**	**18%**
Destination	**117**	**28%**
Workplace	**174**	**42%**

Figure 2: Level 2 Site Host Category Participation (Pilot + Permanent Program)

Workplace Charging in Jackson

Based on the rebate verification documentation received for completed public Level 2 sites as of March 31, 2025, a breakdown of project costs is outlined in Figure 3 below.

Per Dual Cord L2	Median Cost	Average Cost
Total Project Cost (Installation, Network & Maintenance Plan Fees, + Charging Station Equipment)	$9,423	$12,264

Figure 3: Public L2 Site Project Costs Per Dual-Cord L2

Installation and electrical upgrades at each site continue to be the greatest variable in total project costs. Sites requiring longer extensions of electrical service or underground wiring had higher project costs. Sites that installed pedestal mounted chargers had higher equipment costs than sites that opted for wall mounted chargers, and networked chargers are more expensive than unnetworked L2.

In some circumstances, sites completed installation of chargers and experienced challenges with maintaining a WIFI signal, resulting in the need for technical troubleshooting or additional equipment to extend or strengthen network range. In addition to the networking costs, these reliability challenges are why more sites are interested in un-networked L2s, utilizing a permit fee, or offering L2 charging at no additional cost as an amenity to attract customers.

Community Charging in Rockford

Fleet charging setup at a rental car agency

Figure 4 below identifies locations of sites which have completed installation and received Level 2 charging station rebates as of March 31, 2025.

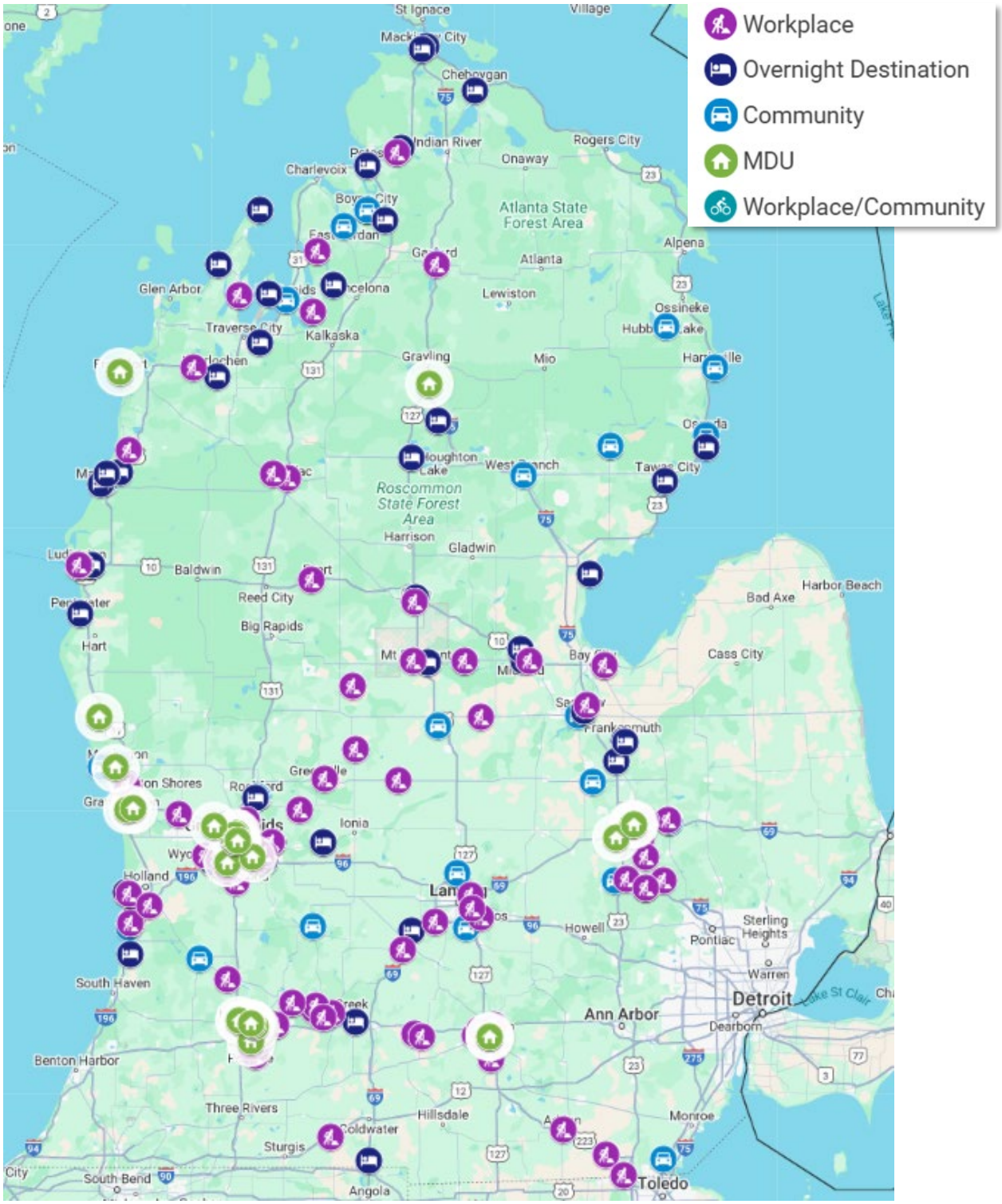


Figure 4: Public Level 2 Sites by Location & Type

DCFC Pilot

As of March 31, 2025, the continued implementation of the PowerMIDrive fast charging pilot had awarded a total of 88 of the 137 committed DCFC rebates for operational sites across the Company's service territory. The 49 DCFC projects still underway include 24 sites selected by MDOT to receive NEVI funding.

As part of our partnership with MDOT on DCFC sites awarded NEVI funding, we have begun make ready upgrade evaluations including a project scope and cost estimate for each site. This information will be included in each contractual agreement between NEVI site hosts and MDOT. The team is fully prepared with make ready plans and equipment to complete these projects once contracting is complete.

Because NEVI sites require four 150kW charge ports to qualify for federal funding, Consumers Energy is designing each NEVI site with a 750KVA transformer to ensure the infrastructure is adequate for the higher load of the chargers. Non-NEVI sites are more likely to utilize a transformer between 300 kVA and 500 kVA. In general, all these transformers are in short supply and can have lead times of 18-24 months, which is why the PowerMIDrive team is so focused on preparations for installation.

The PowerMIDrive team works in close collaboration with our Distribution Planning and Supply Chain partners to ensure we are forecasting new demand accurately and placing long lead time orders for higher power transformers, which have been challenged by supply chain limitations in the last several years. We encourage customers considering DCFC and large fleet projects to reach to us so that timelines can be optimized, and are actively working with EPRI and the EVs2Scale program to proactively forecast infrastructure needs to ensure timely installations in support of electrification.

Based on rebate verification documentation received for completed DCFC customer projects, a breakdown of project costs, excluding make ready upgrades, is outlined in Figure 5. Projects to date have primarily ranged between 125 kW and 200 kW.

	Median Cost	Average Cost	Standard Deviation
Total Project Cost **Scope includes installation, Network & Maintenance Plan Fees, and Charging Station Equipment**	$163,690	$192,163	$63,844
Project Cost in $/kW	$972	$1,010	$355

Figure 5: DCFC Site Project Costs

Figure 6 below outlines the breakdown of make-ready expenses for the 88 completed DCFC rebates in PowerMIDrive through March 31, 2025.

	Median Cost	Average Cost	Standard Deviation
DCFC Make Ready Scope includes 300-750 kVA transformer and service meter, underground or overhead multiphase extension, boring costs, and local system upgrades	$31,612	$40,014	$19,544
Make Ready Cost in $/kW	$189	$253	$128

Figure 6: DCFC Site Make Ready Costs

A DCFC in Wellston helps power travel between Manistee and Cadillac along the M-55 Corridor

A DCFC in Big Rapids aids EV travel along US-131

Figure 7 shows the geographic distribution of the 88 operational PowerMIDrive DCFC Rebate Sites and the 49 remaining fast charging rebates committed to projects in progress at customer locations. Consumers Energy does not own or operate any of these sites. All rebates are awarded to customers. Work remains to be done to support travel in much of our rural territory and tourist destinations.

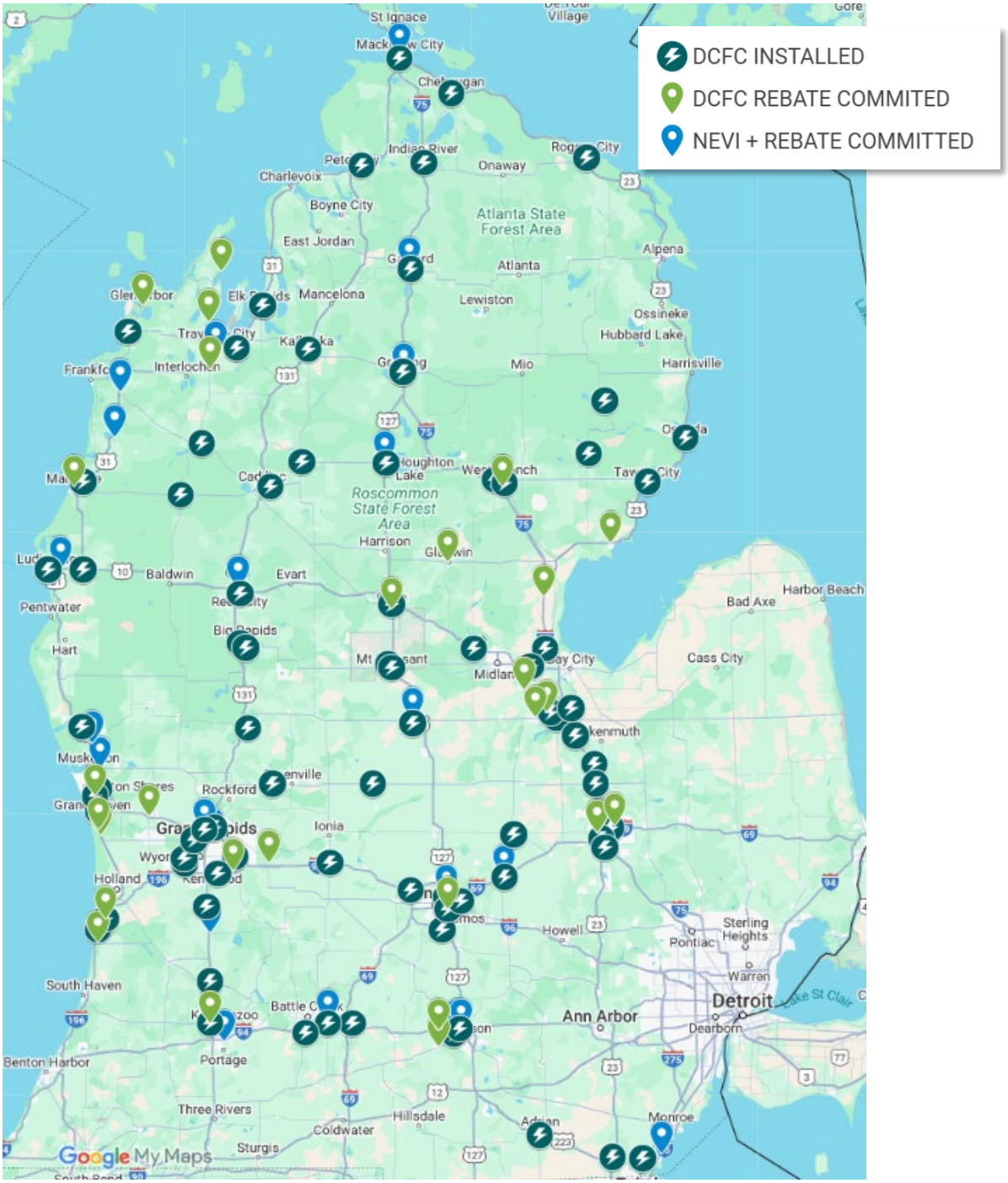


Figure 7: Fast Charging Locations

PowerMIFleet

As of March 31, 2025, a total of 61 customer fleet electrification assessments have been completed (most during the pilot phase), with four additional assessments still in progress. The strongest interest in assessment participation has been in the education and municipal sectors in aid of grant applications and funding requests, followed by small- to medium-sized retail businesses and transportation. This is why the permanent program chose to focus on these sectors, as they need the most assistance to transition to electric. As an additional benefit, fleet assessments within these sectors also benefit a large number and wide variety of Michiganders given their service territories. Figure 8 illustrates the breakdown of assessment participation for all 65 fleet assessments by customer sector.

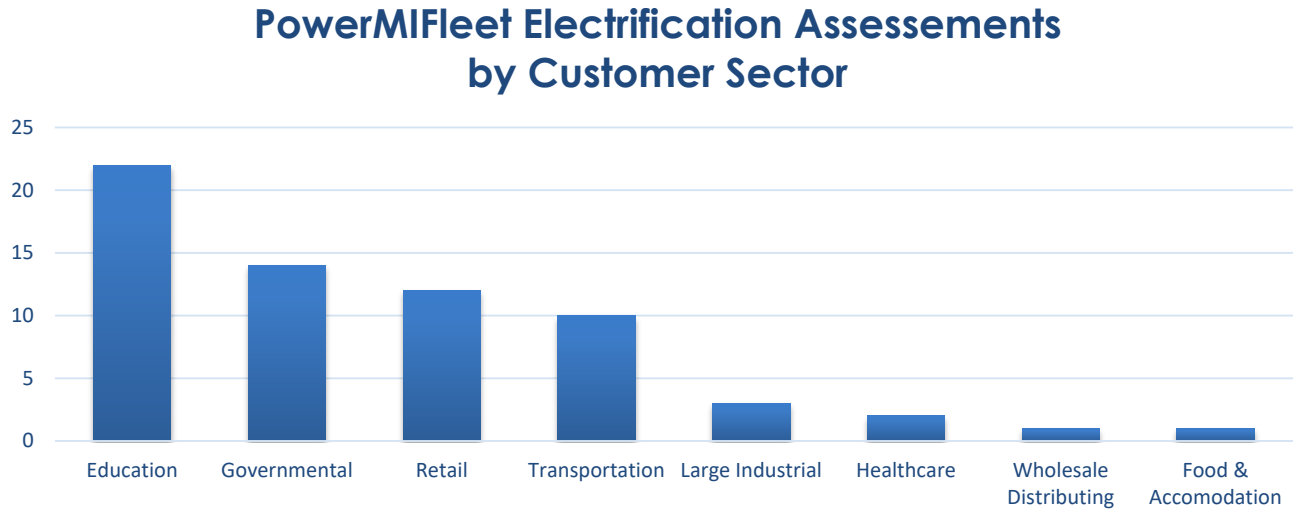


Figure 8: PowerMIFleet Assessments by Customer Sector

For the 61 completed customer fleet assessments to date, a total of 8,398 total vehicles were evaluated, with 2,987 of those vehicles, or 35%, recommended for electrification. In other words, more than 1 out of 3 vehicles are projected to save these agencies money compared to their ICE equivalent.

The PowerMIFleet team has established a quarterly follow-up cadence with assessment participants to provide technical support and guidance as organizational decisions are made to electrify fleet vehicles. In several cases, we have proactively provided workplace charging rebates to customers who wish to establish a network of chargers for employee use in preparation for future fleet EV deployment.

Furthermore, fleet charging rebates have also been provided to customers who did not require a fleet assessment prior to deploying fleet EVs. Going forward, fleet assessments will be reserved for novel fleet use cases where new learnings are available, or where a customer

fleet demonstrates that this service will bring their organization value, supporting an imminent fleet deployment.

As of March 31, 2025, a total of 137 L2 charger rebates and 11 DC charger rebates have been paid to PowerMIFleet program participants. An additional 79 L2 charger rebates and 88 DC long duration charger rebates are committed to customers with in-progress projects. Note that the majority of school districts awarded Michigan and/or EPA Clean School Bus funding make up nearly 100% of the long-duration DC charger rebates committed to in-progress projects at this time.

To date, PowerMIFleet rebates have supported a total of 240 vehicle deployments, with an additional 323 deployments anticipated in the next year. Figure 9 illustrates the breakdown of PowerMIFleet program participants' fleet electrification status by vehicle type to date, with more EVs yet to come given purchasing schedules, and state or federal funding award timelines.

A school district installs 30kW Long-Duration DC chargers to power new electric school buses

Some vehicles on order, or projects anticipated this year may ultimately become delayed or canceled due to the revocation of previously announced and/or awarded federal funding or contracts (e.g., Oshkosh mail delivery trucks, EPA Clean School Bus Grants).

However, until we have received confirmation of a project's cancelation, the totals will be included in "vehicles on order" category of Figure 9 below, and we will continue to partner with these customers to ensure their projects are successful if able to progress to deployment.

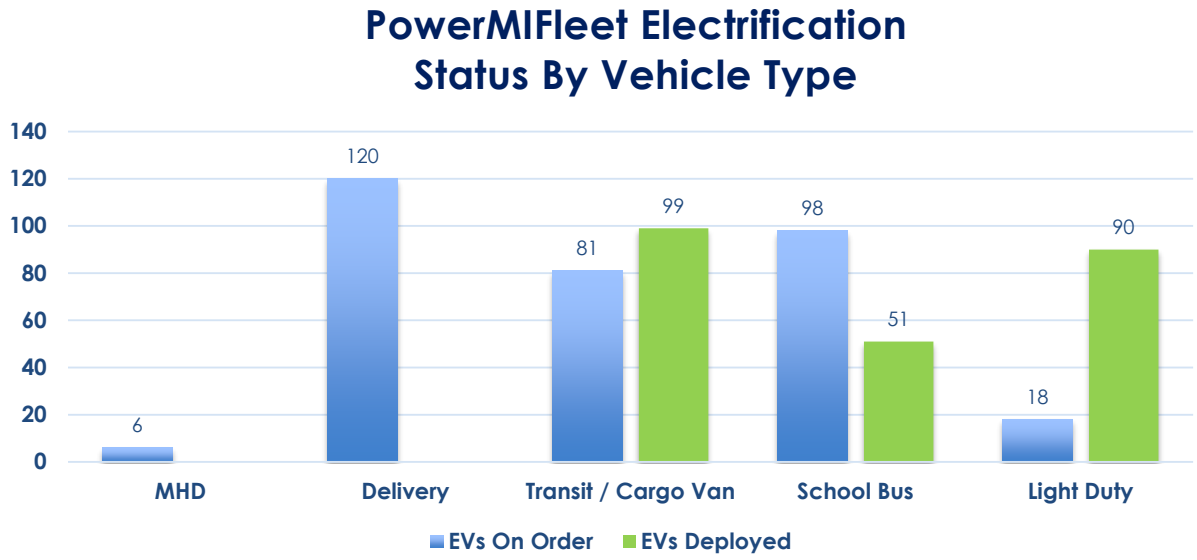


Figure 9: PowerMIFleet Customer Electrification Status by Vehicle Type

Fleet EVs can be operated and charged while loading indoors because there are no emissions, thereby creating new opportunities for building redevelopment

Consumers Energy helped the DNR electrify portions of their fleet and supported park visitors via L2s in State Parks for the Lake Michigan Circuit at Ludington and Pentwater

Finally, Figure 10 shows the geographic distribution of PowerMIFleet customer electrification projects as of March 31, 2025. The program team has intentionally sought projects from across our entire service territory to ensure fleet electrification benefits a wide variety of customers and use cases.

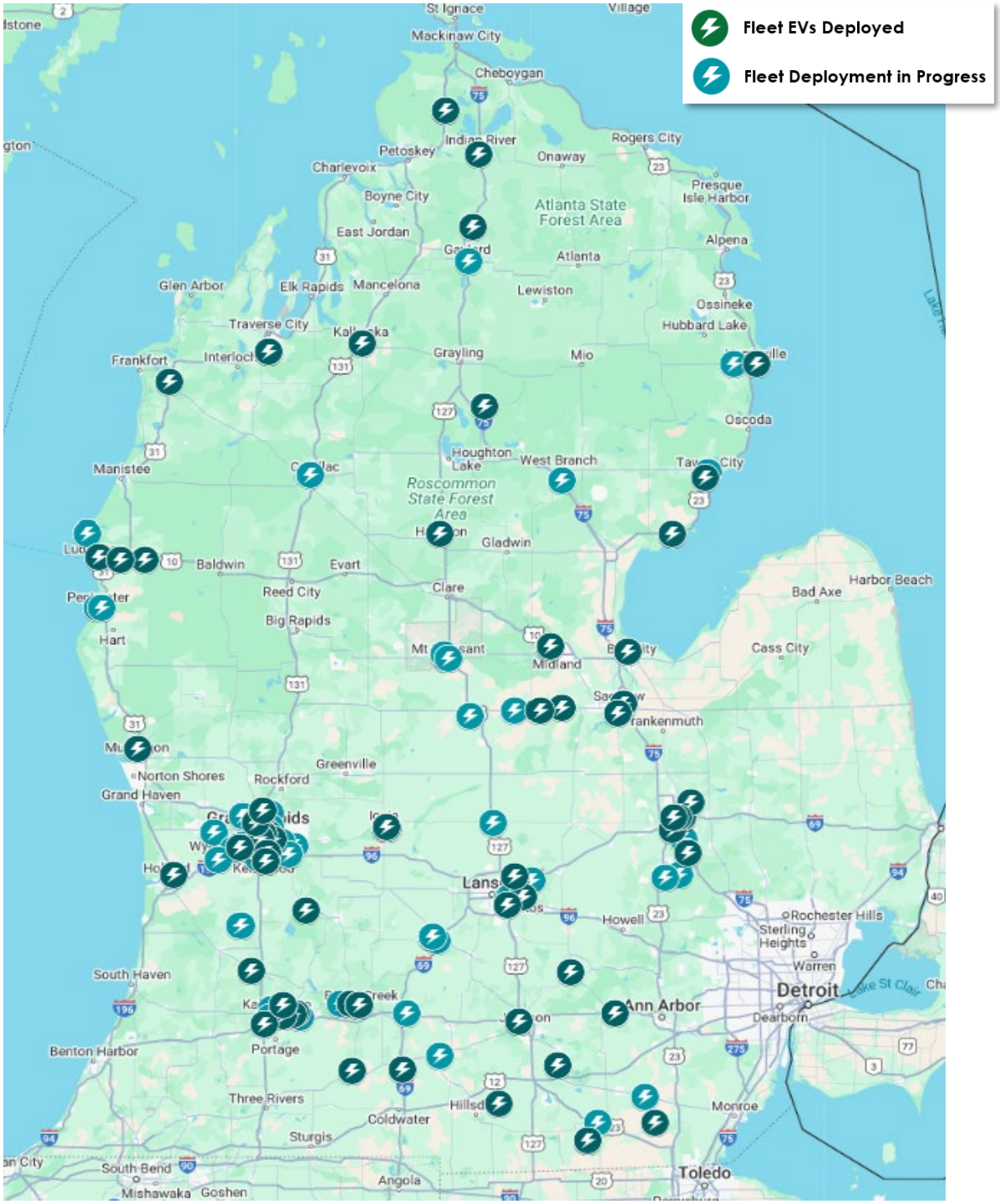


Figure 10 PowerMIFleet Customer Electrification Locations

Customer Education & Outreach

Through education and outreach efforts, the PowerMIDrive team was able to reach over 10,100 people. This includes 570 customers participating in our ride and drives, allowing them to experience driving electric and engage in program conversations regarding off-peak charging and TOU rates. Notably, 80% of the drivers experienced driving electric for the first time at our event.

PowerMIDrive team at 28th St. Metro Cruise

Between 2020 and 2024, the number of EVs in the Company's electric territory has grown dramatically, from approximately 8,800 EVs to nearly 40,000, which is a factor of 4.5 times. Given the rapidly growing state of EV market adoption, it is extremely important to identify segments of customers who are likely to already own an EV or purchase an EV as their next vehicle, and to get in front of the even larger number of customers intending to drive an EV in the future.

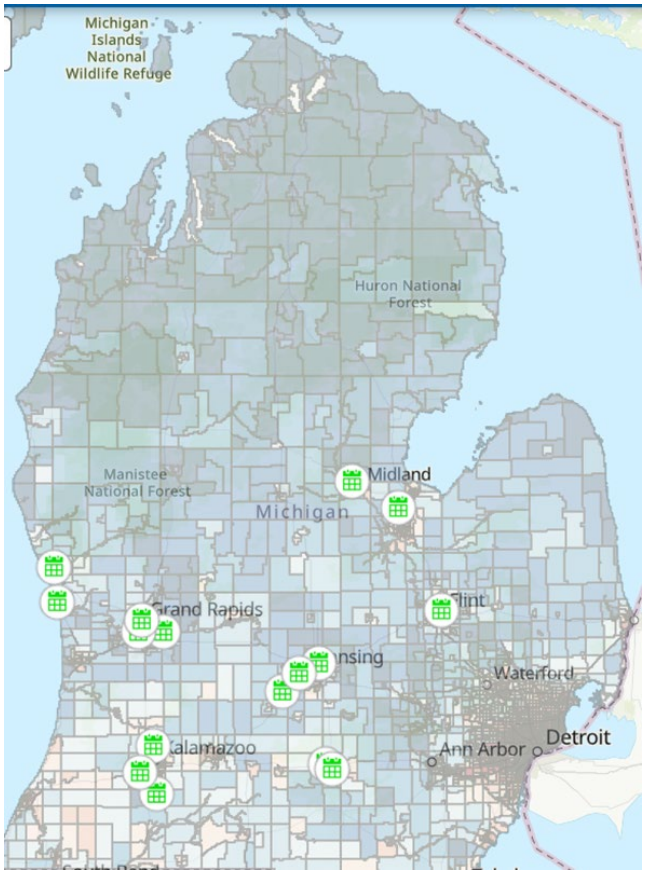


Figure 9: In-Person Customer Education & Outreach Locations Overlaid on MIEJ Screen Map

The number of direct customer contacts via phone calls and email communications has been high. A significant level of effort can be needed to assist customers with understanding their charging options, rate options, vehicle charging questions, and concerns about successful business models for public charging. This is why we have worked to continually enhance our website and outreach materials. In the last year, the program team made over 33,000 direct communications with EV customer contacts. This averages about 127 customer contacts per working day!

The level of specialized customer support has demonstrated that permanent staffing for EV customer specialists is a clear requirement for continued success. Our customer interactions also provide the team with direct insight into the challenges EV customers face regarding charging infrastructure, both at home and in public.

There is no substitute for getting in front of an engaged and interested audience, and Consumers Energy has actively sought such opportunities to educate customers about the benefits of pairing EVs with TOU rates, the expansion of public charging infrastructure, and EV charging etiquette. Over the last year,

The PowerMIDrive team hosted or attended 67 EV engagement events as presenter, panelist, or exhibitor, which is more than one per week. These events reached close to 4,000 participants, including many potential future EV drivers. Of these events, 8 were conducted within MIEJ (70+) and 3 in Justice 40 areas.

PowerMIDrive sponsored Clean Fuels Michigan's Disrupt event supporting EV charging start-ups

As shown in Figure 15, the program team organized and executed public L2 and DCFC charging station ribbon cutting ceremonies, car shows and ride and drives (e.g., Drive Electric Earth Day and National Drive Electric Week), EV101 presentations to both online and in-person, and EV driver social events.

The PowerMIDrive team at the Jackson Ride and Drive

We have found in-person events to be quite valuable in creating word of mouth campaigns for the program, earned media that helps reiterate program messaging, getting PowerMIDrive information into the hands of EV drivers and the EV curious, and often leading to additional speaking engagements for educational opportunities.

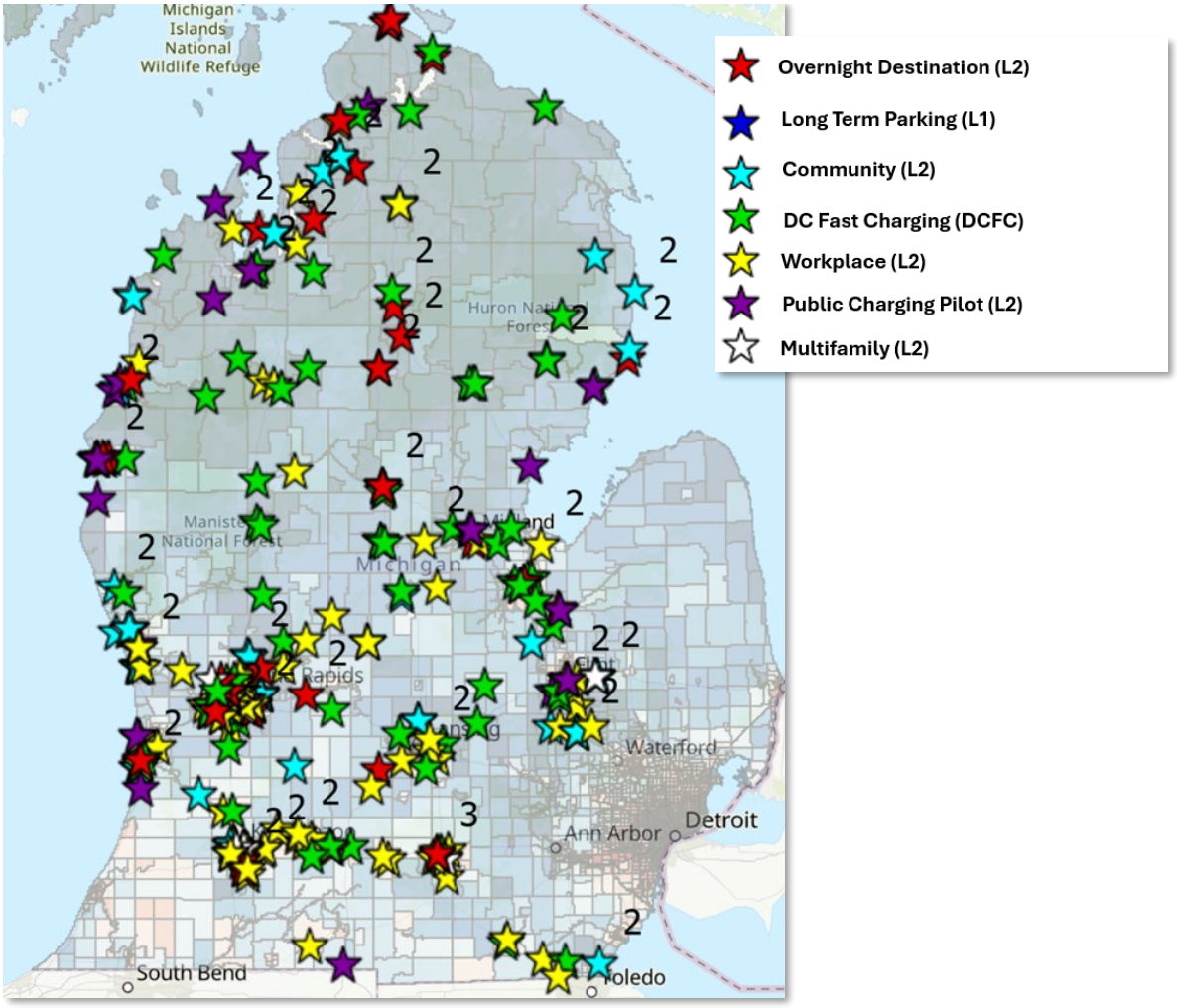
Customers get an overview of EVs before their ride and drive in Flint

Charging Up Underserved Communities

The PowerMIDrive and PowerMIFleet teams have also started tracking charging infrastructure rebates awarded within Justice 40 and MIEJ Screen areas of 70 and greater. The table and map below illustrate the results to date. We continue to actively engage with potential site hosts in these areas for rebate applications.

Site Host Category	Rebates in EJ40	Rebates in MIEJ 70+
Multifamily	**12**	**24**
Community Charging	**11**	**13**
Destination	**10**	**11**
Workplace	**15**	**41**
Public DCFC	**4**	**6**

Figure 12: EJ Rebates



TEP MANAGED CHARGING RESULTS

Charging Time Summary

A key strategy of our TEP customer programs is to maximize off-peak charging (residential and commercial) to benefit all customers via downward rate pressure and improved reliability. Optimized EV charging also directly supports our one-million EV by 2030 readiness in collaboration with Michigan's two million EV goal.

When the customer EV load management pilots initially began, it was projected that approximately 80% of charging would occur at home and 20% via public charging. The very first pilot also aimed to steer EV load to at least 70% off-peak charging. Initial pilot data tracked toward the 80/20 residential vs commercial projection but is now nearing 55/45 given the dramatic growth in demand for public charging. Furthermore, the TEP pilots not only achieved over 80% off-peak charging, but continued to optimize such that the total portfolio is now 89.6% off-peak!

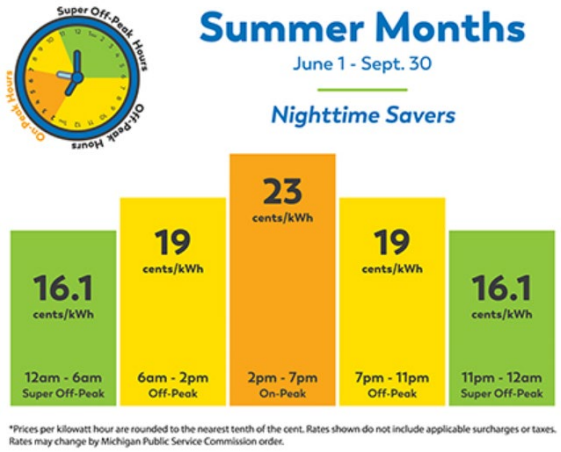
Per Figure 13, Consumers Energy is pleased to report that off-peak charging has continued despite the dramatic 42.8% year over year (YOY) load growth across all categories and is still achieving world-class results with 95.9% off-peak charging across all the permanent customer programs! However, the EV charging market continues to evolve and significant growth in commercial charging is occurring. YOY load growth in community, multifamily, destination, workplace and DCFC indicate that these remain important areas for the TEP going forward. The continued changes in the market are reflective of both increased miles driven by EV, and PowerMIFleet data which shows that many light duty EVs provide cost savings for fleets.

EV Customer Program Category	On-Peak 2PM-7PM	Off-Peak 7AM-2PM 7PM-11PM	Super Off-Peak 11PM-7AM & Weekends	Total Off-Peak by Category	Total kWh by Category	YOY Load Growth
Residential Single Family	*2.1%*	*6.6%*	*91.3%*	*97.9%*	*53.8%*	*8.7%*
Community Charging	*21.6%*	*33.8%*	*44.6%*	*78.4%*	*1.3%*	*26258.6%*
Multifamily	*18.3%*	*35.2%*	*46.5%*	*81.7%*	*0.3%*	*162.9%*
Total Residential	***2.6%***	***7.4%***	***90.0%***	***97.4%***	***55.3%***	***11.6%***
Destination L2+L1	*20.6%*	*36.3%*	*43.1%*	*79.4%*	*1.4%*	*69.8%*
Fleet & Workplace	*8.9%*	*40.8%*	*50.3%*	*91.1%*	*12.1%*	*64.5%*
DCFC Pilot	*24.5%*	*35.2%*	*40.3%*	*75.5%*	*31.1%*	*154.7%*
Total Commercial	***20.1%***	***36.8%***	***43.1%***	***79.9%***	***44.7%***	***118.7%***
TEP Programs	**4.1%**	**13.9%**	**82.0%**	**95.9%**	**68.9%**	**19.1%**
TEP Programs & DCFC Pilot	***10.4%***	***20.5%***	***69.0%***	***89.6%***	***100.0%***	***42.8%***

Figure 10: EV Charging per Category & Time Block
April 2024 to March 2025

Figure 13 above shows the percentage of charging that happens in different on-peak and off-peak time blocks, in addition to the percentage of charging per category. In the residential sector, single family charging continues to lead all categories, with 97.9% off-peak charging and 53.8% of the measurable EV load. Community charging, which launched in 2023 and remains a very small 1.3% of the total kWh, is growing more rapidly than any other category (26,258.6%!) indicating high demand for equitable charging access. Multifamily properties are also still a small percentage of the total at 0.3%, but experiencing strong YOY load growth of 162.9%. The program team is leaning in with continued outreach efforts for multifamily and community charging.

A multifamily charging installation with off-peak signage



Example of TOU rate informational materials

In the commercial space, the fleet and workplace programs are also performing well, with 91.1% off-peak charging, 12.1% of the total kWh, and 64.5% YOY load growth due to rapidly increasing EV adoption and the need for equitable charging access that workplaces can provide. Public L2 destination charging is still a small component of the total kWh at 1.4%, but growth of 69.8% YOY is indicating strong demand for this off-peak charging opportunity as more overnight and weekend EV travel locations are being enabled. Moreover, destination L2 infrastructure helps infill the still emerging but fast growing DCFC infrastructure to aid long distance travel and replicates the residential overnight charging experience that many customers are used to.

Our position remains that DCFC infrastructure is highly unlikely to benefit from managed charging other than through technological means (e.g., pairing with battery storage for energy arbitrage in the future as battery prices continue to fall and where make ready costs are higher than average) that do not impact the customer experience.

Customers needing to charge immediately to get to their location are unlikely to accept active charge management that increases their charging duration or be deterred by marginally higher costs when charging is a necessity to reach their destination.

However, fast charging is a key enabler of EV adoption in areas lacking infrastructure and off-peak utilization is still a respectable 75.5% given weekend travel to the many tourist destinations in Consumers Energy's electric territory. Given these factors, and the strong

utilization illustrated by 154.7% YOY load growth at host sites that have installed DCFCs, we believe it is prudent to incentivize one more round of fast charging rebates for communities lacking in infrastructure, which at this point are largely more rural areas with seasonal traffic. These communities will also benefit from attracting EV travelers coming from longer distances, such as Detroit, Toledo, and Chicago to Michigan's great destinations.

Fast charging sites in larger urban areas like Grand Rapids are likely to have a multitude of chargers

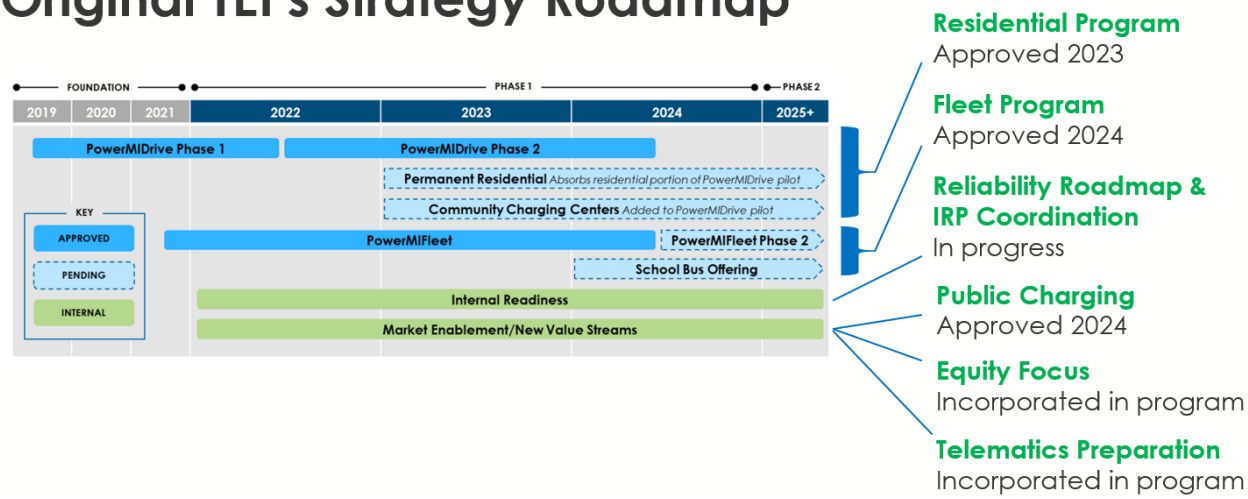
Fast charging sites up north and in more rural areas are more likely to only have two plugs, thereby challenging seasonal traffic and economic benefits to the community

TEP LOOKING FORWARD & STAKEHOLDER FEEDBACK

As an annual update, no changes to the Company TEP strategies are proposed in this report. With the goals from the first phase of the original TEP filing[5] complete, the Company continues to implement the present TEP to ensure:

1. Load growth at the right time to benefit reliability and cost for all customers.
2. Encourage EV adoption and prepare for the millions of EVs that will be on the road.
3. Utilize margin from EV load growth to pay for EV load management programs while also creating downward rate pressure for all customers.

Original TEPs Strategy Roadmap



The currently planned phases of the Company TEP logically expand upon existing programs and tactics. In early 2026 the Company will again engage stakeholders regarding potential changes to future phases of our TEP and file an updated TEP by July 2026.

Future TEP Roadmap

[5] See page 19 of Exhibit A-152 (JAM) in Case No. U-21224, which is page 2937 of 2942 in the PDF: 0688y000002IGMlAAM (site.com)

A fast-charging site in Saginaw supported by PowerMIDrive offers excellent lighting and a canopy

Explore our TEP programs at: ConsumersEnergy.com/EV

Power MI Drive | Power MI Fleet | Consumers Energy Count on Us®

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file transportation electrification plans and for other related matters.	)))))	Case No. U-21538

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 27, 2025, she served an electronic copy of **Consumers Energy Company's Transportation Electrification Plan Annual Progress Report 2025** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 27th day of June 2025.

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-21538

Party	Mailing Address	Email Address
Administrative Law Judge		
Hon. Sally L. Wallace	7109 W. Saginaw Hwy., 3rd Floor Lansing, MI 48917	wallaces2@michigan.gov
Consumers Energy Company		
Gary A. Gensch, Jr., Esq. Bret A. Totoraitis, Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq.	One Energy Plaza Jackson, MI 49201	gary.genschjr@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com spencer.sattler@cmsenergy.com evan.keimach@cmsenergy.com mpsc.filings@cmsenergy.com
Michigan Public Service Commission Staff		
Nicholas Q. Taylor, Esq. Anna B. Stirling, Esq. Alena Clark, Esq. Daniel Sonneveldt, Esq. Lori Mayabb	Assistant Attorneys General Public Service Division 7109 W. Saginaw Hwy., 3rd Floor Lansing, MI 48917	taylorn10@michigan.gov stirlinga1@michigan.gov clarkA55@michigan.gov sonneveldtd@michigan.gov mayabbl@michigan.gov
Attorney General Dana Nessel		
Celeste R. Gill, Esq. Amanda Churchill	ENRA Division 525 West Ottawa Street 6th Floor Williams Building Post Office Box 30755 Lansing, MI 48909	gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
Michigan Cable Telecommunications Association ("MCTA")		
Sean P. Gallagher, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan Street Suite 1000 Lansing, MI 48933	sgallagher@fraserlawfirm.com
Michigan Environmental Council, Natural Resources Defense Council, Citizens Utility Board of Michigan, and Sierra Club		
Holly L. Hillyer, Esq. Christopher M. Bzdok, Esq. Tracy Jane Andrews, Esq. Natasha Fowles	Troposphere Legal 420 East Front Street Traverse City, MI 49686	holly@tropospherelegal.com chris@tropospherelegal.com tjandrews@tropospherelegal.com natasha@tropospherelegal.com
The Kroger Co.		
Kurt J. Boehm, Esq. Jody Kyler Cohn, Esq. Michael L. Kurtz, Esq.	Boehm, Kurtz & Lowry 36 East Seventh Street, Ste. 1510 Cincinnati, OH 45202	kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com mkurtz@bkllawfirm.com
Michigan Municipal Association for Utility Issues		
Valerie J.M. Brader, Esq.	Rivenoak Law Group, P.C. 3331 W. Big Beaver Rd, Ste. 109 Troy, MI 48084	valerie@rivenoaklaw.com ecf@rivenoaklaw.com
Rick Bunch	Executive Director and Chairman Michigan Municipal Association for Utility Businesses 4989 Earhart Road Ann Arbor, MI 48105	rick@mi-maui.org
Ford Motor Company		
Valerie J.M. Brader, Esq.	Rivenoak Law Group, P.C. 3331 W. Big Beaver Rd, Ste. 109 Troy, MI 48084	valerie@rivenoaklaw.com ecf@rivenoaklaw.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21538

Energy Michigan, Foundry Association of Michigan, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Advanced Energy United, Energy Michigan, Inc., and The Foundry Association of Michigan.		
Timothy J. Lundgren, Esq. Laura A. Chappelle, Esq. Justin K. Ooms, Esq.	Varnum LLP PO Box 352 Grand Rapids, MI 49501	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com jkooms@varnumlaw.com
Michigan Energy Innovation Business Council and Advanced Energy United		
Dr. Laura S. Sherman	Michigan EIBC 115 W. Allegan, Ste. 710 Lansing, MI 48933	laura@mieibc.org
The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar		
Nicholas Wallace, Esq. Daniel Abrams, Esq. Alondra Estrada Carolyn Boyce	Environmental Law & Policy Center 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	nwallace@elpc.org dabrams@elpc.org aestrada@elpc.org cboyce@elpc.org mpscdockets@elpc.org
Michigan Electric Transmission Company, LLC		
Richard J. Aaron, Esq. Olivia R.C.A. Flower, Esq. Hannah Buzolits, Esq. Courtney F. Kissel, Esq.	Dykema Gossett PLLC 201 Townsend Street, Suite 900 Lansing, MI 48933	raaron@dykema.com oflower@dykema.com HBuzolits@dykema.com ckissel@dykema.com mpscfilings@dykema.com
Urban Core Collective		
Amanda Urban, Esq. Mark Templeton, Esq. Jacob R. Schuhardt, Esq. Sam Heppell, Esq. Madison Wilson	Univ of Chicago Law School – Abrams Env Law Clinic 6020 South University Avenue Chicago, IL 60637	t-9aurba@lawclinic.uchicago.edu templeton@uchicago.edu jschuhardt@uchicago.edu heppell@uchicago.edu madisonswilson@uchicago.edu aelc_mpsc@lawclinic.uchicago.edu
Association of Businesses Advocating Tariff Equity		
Stephen A. Campbell, Esq. Michael J. Pattwell, Esq.	Clark Hill PLC 500 Woodward Avenue, Suite 3500 Detroit, MI 48226	scampbell@clarkhill.com mpattwell@clarkhill.com
Hemlock Semiconductor Operations LLC		
Jennifer Utter Heston, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan Street Suite 1000 Lansing, MI 48933	jheston@fraserlawfirm.com
Great Lakes Renewable Energy Association		
Don L. Keskey, Esq. Brian W. Coyer, Esq.	University Office Place 333 Albert Avenue, Suite 425 East Lansing, MI 48823	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Walmart, Inc.		
Melissa M. Horne, Esq.	Higgins, Cavanagh & Cooney, LLP 10 Dorrance Street, Suite 400 Providence, RI 02903	mhorne@hcc-law.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21538

American Federation of Labor and Congress of Industrial Organizations, Michigan State Utility Workers Council, Utility Workers Union of American, Local 223		
Benjamin L. King, Esq.	McKnight, Canzano, Smith, Radtke & Brault, P.C. 3950 W. 11 Mile Road Berkley, MI 48072	bking@michworkerlaw.com
DTE Electric Company		
Jon P. Christinidis, Esq.	One Energy Plaza, 1635 WCB Detroit, MI 48226	jon.christinidis@dteenergy.com
Michigan Electric and Gas Association		
Daniel Dundas, Esq.	7201 W. Saginaw Hwy., Ste. 305 Lansing, MI 48917	dan@megautilities.org

* 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-21870

REVISED DIRECT TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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 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 upgrade or modifications to substations or building 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. What is the purpose of your direct testimony in this proceeding?

A. As introduced by Company witness Michael P. Kelly, 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.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is 2024. The bridge period consists of the 16 months ending April 30, 2026. The test year is the 12 months ending April 30, 2027.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-166 (JMP-1)	Bridge Period LVD Project List;
Exhibit A-167 (JMP-2)	Test Year LVD Project List;
Exhibit A-168 (JMP-3)	Conservation Voltage Reduction Measurement and Verification Independent Assessment; and

Exhibit A-169 (JMP-4)	Summary of 2023 and 2024 LVD Repetitive Outages Investment.

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

A. Yes, except that Exhibit A-168 (JMP-3) is an independent assessment prepared by a third party.

TABLE OF CONTENTS

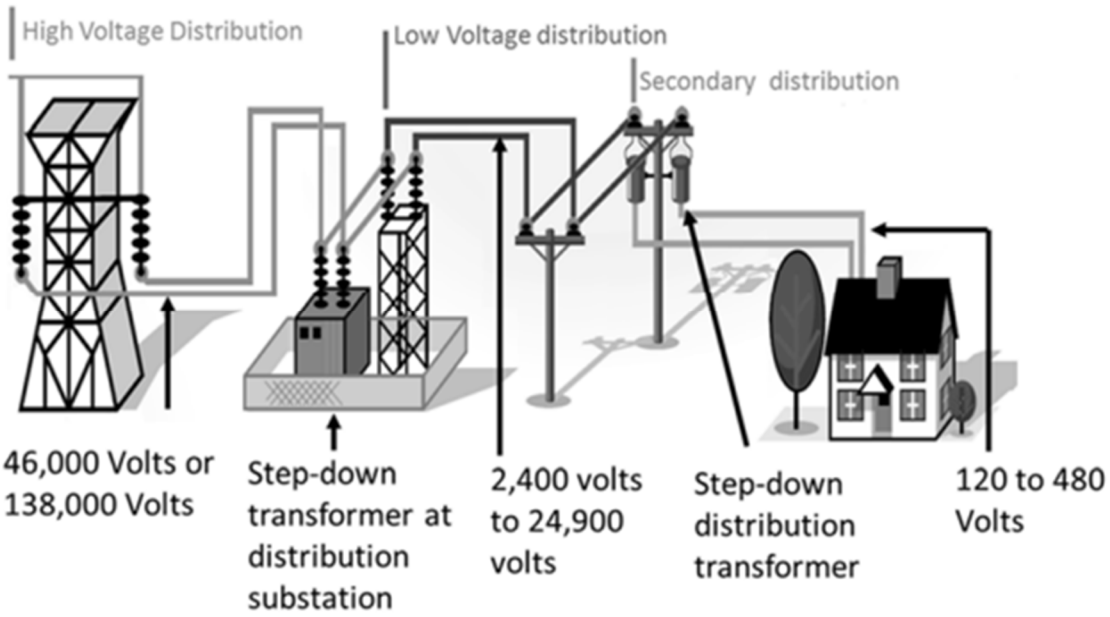
LVD System Overview 4
LVD Programs with Capital Spending 6
New Business Program 8
LVD Lines New Business 8
Demand Failures Program 16
LVD Lines Demand Failures 17
Asset Relocations Program 27
LVD Asset Relocations 27
Reliability Program 37
LVD Lines Reliability 41
LVD Repetitive Outages 73
LVD Lines Rehabilitation 81
Resiliency 91
Capacity Program 107
LVD Lines Capacity 108
LVD New Business Capacity 117
Conservation Voltage Reduction 122
Metering and Transformers 127
LVD Metering 128
LVD Transformers 135
Electric Other Program 141
Tools 141
Summary 147

LVD SYSTEM OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. As discussed by Company witness Kelly, 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 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 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 2,000 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. Even with advances in distribution automation, 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's strategy has been provided in detail in the 2023 Reliability Roadmap, also known as the *Electric Distribution Infrastructure Investment Plan* ("2023 EDIIP"), that was filed in Case No. U-20147 on September 27, 2023, an amended version of which is included in this case as Exhibit A-129 (MPK-19). Company witness Kelly provides direct testimony explaining the Reliability Roadmap. 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 Kelly, 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 $1,055,533,000 in capital projects on the LVD system in the bridge period, and $1,086,679 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 $791,650,000 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	2024 Actuals	Bridge Period	Test Year
New Business	$239,005	$396,010	$337,982
Demand Failures	$199,432	$231,185	$166,120
Asset Relocations	$51,502	$97,911	$79,090
Reliability	$89,384	$248,078	$406,130
Capacity	$45,101	$72,347	$89,110
Electric Other	$7,773	$10,001	$8,248
Total	$632,197	$1,055,533	$1,086,679

Q. How has the level of investment in the LVD system been impacted by the Reliability Roadmap?

A. The Reliability Roadmap did not make a meaningful impact on LVD spending in the New Business, Demand Failures, or Asset Relocations programs. LVD spending in those programs is projected in this case based on relevant data and recent trends as described later in this testimony.

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 connection between 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 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-166 (JMP-1) and A-167 (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."

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 Kelly 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 Kelly 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.

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.

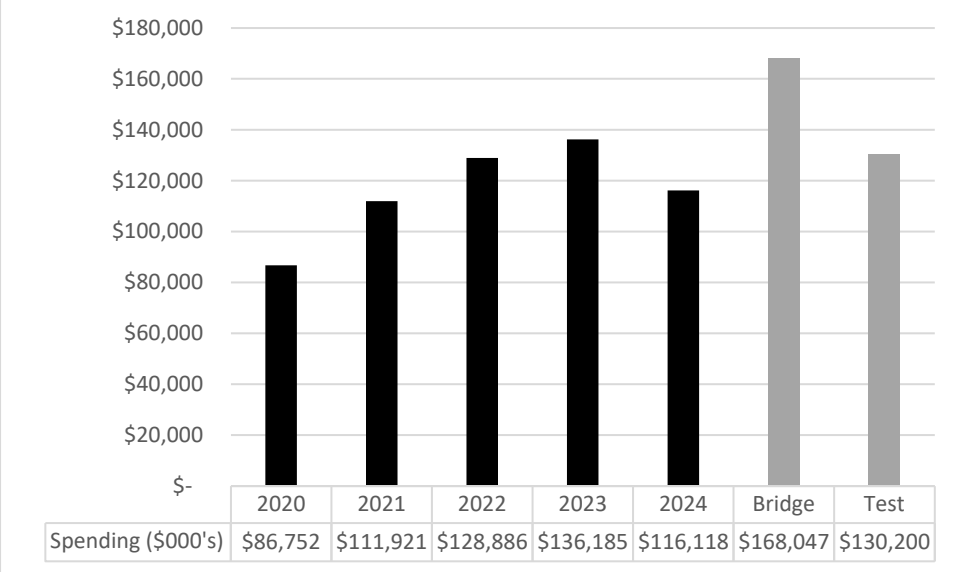
Q. What benefits will customers realize through the Company completing work in the LVD Lines New Business subprogram?

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 $168,047,000 in the bridge period and $130,200,000 in the test year, as shown in Exhibit A-113 (MPK-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-113 (MPK-3), line 1, and below in Figure 3.

FIGURE 3
LVD LINES NEW BUSINESS SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$86,752	$111,921	$128,886	$136,185	$116,118	$168,047	$130,200

Q. How did the Company develop its projected expenditures in this subprogram?

A. Projected expenditures for the LVD Lines New Business Program were based on the expected number of new service connections in the Company's service territory and the projected unit cost of new services.

Q. How does the Company project new service connections?

A. The Company has found that new service connections in its service territory typically track with the number of single-family home permits issued, as reported by the U.S. Census Bureau[1]. Figure 4 below shows the relationship between the two data sets. The Company uses the historical number of new service connections as a foundation for its projections and consults forecasts of single-family housing permits from the Home Builders Association of Michigan ("HBAM") for additional information.

The U.S. Census Bureau data indicates that single family home construction in Michigan increased by 5% in 2024 compared to 2023. The total number of single-family

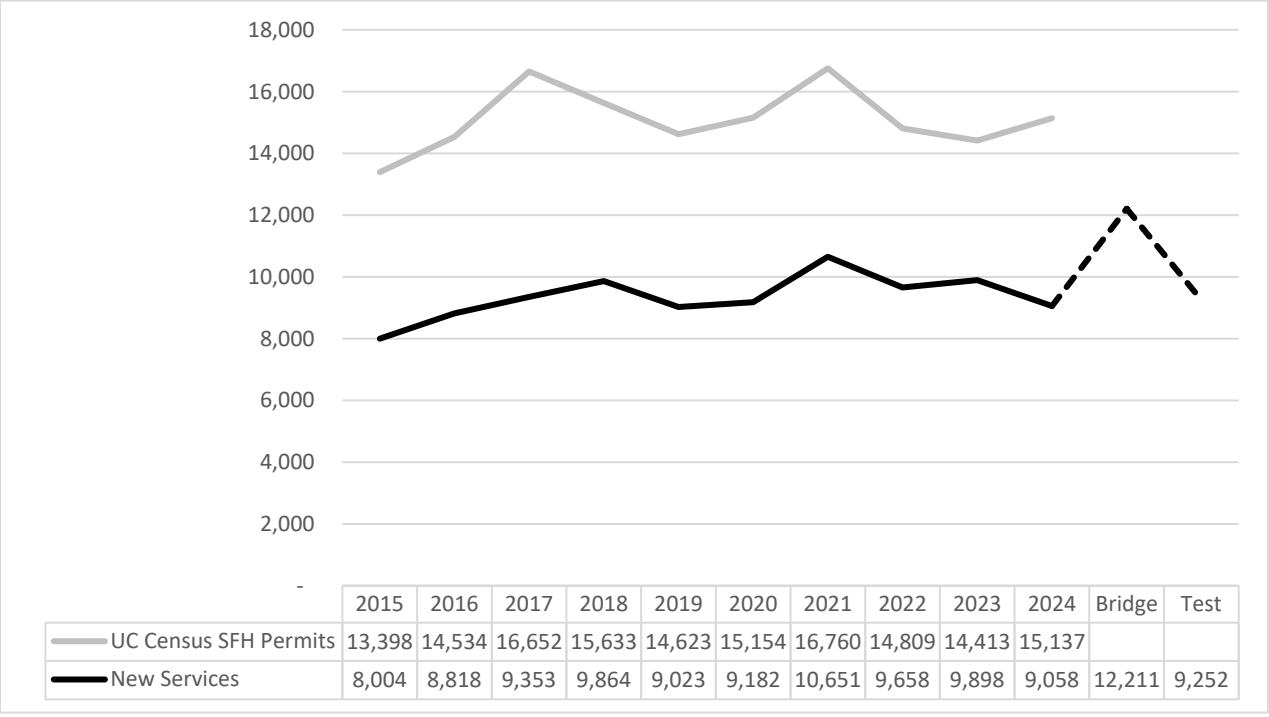
[1] US Census Data: https://www.census.gov/construction/bps/annual.html

housing permits issued in the state last year totaled 15,137 compared to the 14,413 permits that were issued in 2023[2]. In January 2025, HBAM provided a preliminary forecast for 2025 that 15,728 single-family home permits would be issued, a 3.9% increase over 2024.[3] HBAM's forecast supports a growth in Michigan single-family home construction in 2025, and the Company is projecting it will have more new service connections in 2025 and 2026 than in 2024.

Q. What is the Company's forecasted number of new service connections?

A. The Company is projecting 12,211 new service connections for the 16-month bridge period and 9,252 for the test year. Figure 4 below illustrates the historical and projected new service connections.

FIGURE 4
HISTORICAL AND FORECASTED NEW SERVICE CONNECTIONS



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Bridge	Test
UC Census SFH Permits	13,398	14,534	16,652	15,633	14,623	15,154	16,760	14,809	14,413	15,137		
New Services	8,004	8,818	9,353	9,864	9,023	9,182	10,651	9,658	9,898	9,058	12,211	9,252

[2] U.S. Census data: https://www.census.gov/construction/bps/statemonthly.html
[3] HBAM press release: https://hbaofmichigan.com/assets/pdf/Forecast.Release.1.30.25.Final/

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. While unit cost for this subprogram decreased from 2023 to 2024, the Company anticipates unit cost increases for the bridge period and test year relative to the 2024 amount to account for inflation, increasing length of service lines, and increased amount of underground services. Figure 5 below illustrates the historical and projected unit cost for new service connections.

Q. Is the Company proposing any electric service connection fees related to this sub-program in the instant case?

A. The Company is updating its residential and general service fees. The new fees are addressed by Company witness Brittani A. Gray.

Q. Does the Company expect the proposed changes in fees to affect the number of overhead and underground services installed?

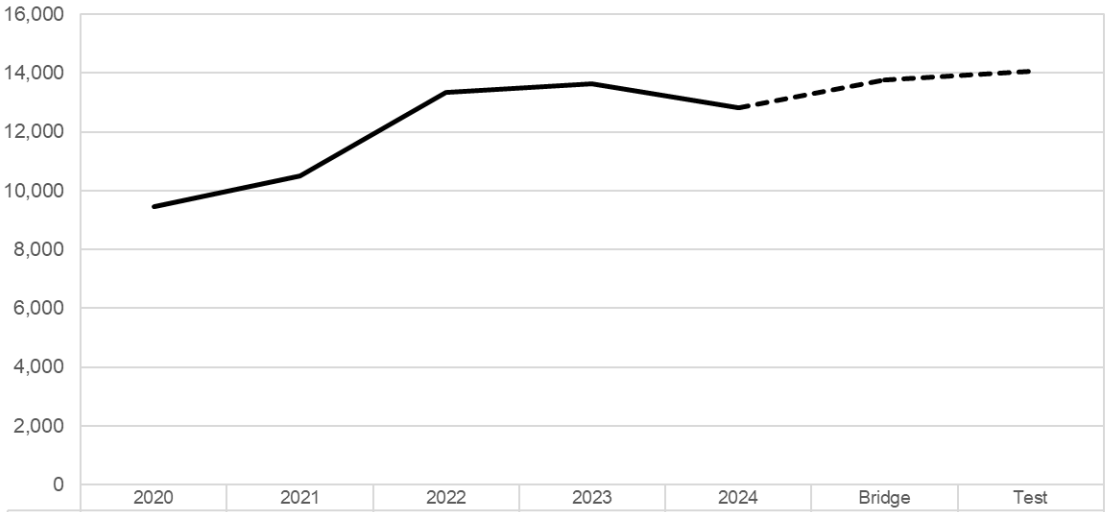
A. Yes. Currently, 87% of the service installations are underground. Given the change in service fees, the Company expects the percentage of underground services to increase to 99%. The 1% of overhead services is expected to remain for customers where an

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 fail 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.

FIGURE 5
HISTORICAL AND FORECASTED UNIT COSTS FOR NEW SERVICE CONNECTIONS



	2020	2021	2022	2023	2024	Bridge	Test
Unit Cost ($)	9,442	10,507	13,340	13,646	12,821	13,762	14,073

Q. Why has the Company experienced increased unit costs in this subprogram in recent years?

A. In addition to inflation, the Company has seen increases in the average length of a new service connection. The Company experienced an increase in unit cost in 2022 due primarily to increased material and contractor costs; however, the Company has worked to reduce its unit cost, resulting in a reduction for 2024.

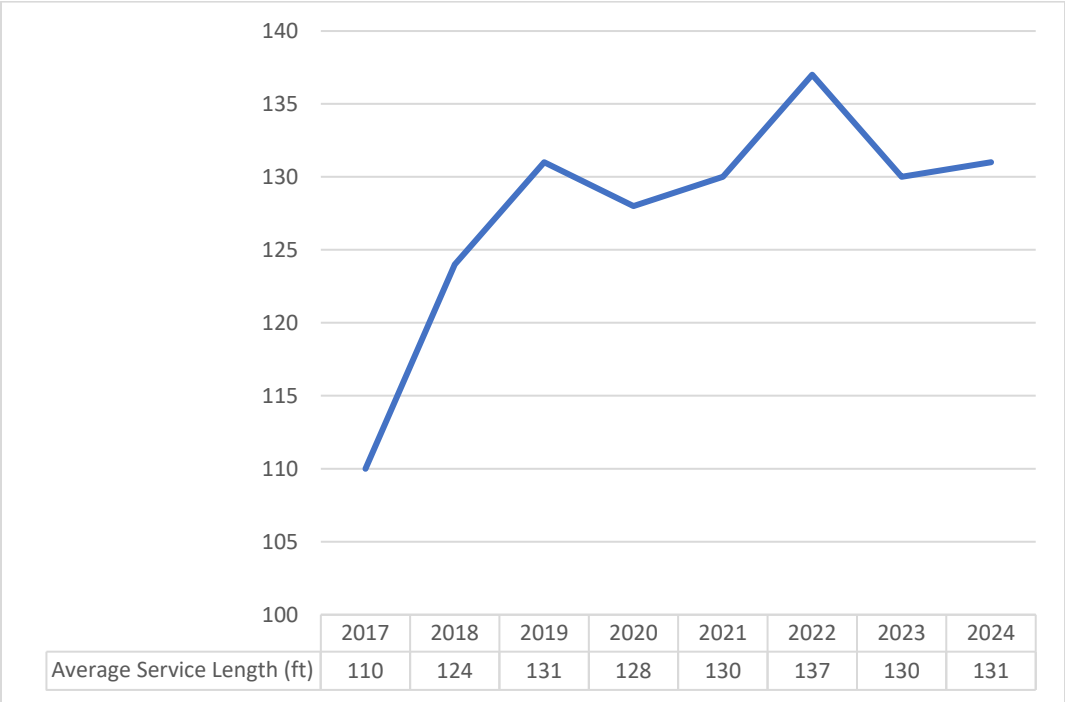
Q. How does the change in the customer service connection fees impact projected spending in this sub-program?

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. Please describe the increases in average service length.

A. Service length is influenced by the optimal route of the service on a customer's property from the Company facilities to the customer's preferred location. The Company has had an increase in average service from 110 feet in 2017 up to 131 feet in 2024, as shown in Figure 6 below.

FIGURE 6
HISTORICAL AVERAGE SERVICE LENGTH



	2017	2018	2019	2020	2021	2022	2023	2024
Average Service Length (ft)	110	124	131	128	130	137	130	131

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 it in the instant case. The results of this analysis are shown in Figure 7 below.

FIGURE 7
COMPARISON OF COMPANY VS. CONTRACTOR UNIT COSTS FOR LVD LINES NEW BUSINESS, 2020-2024

	2020	2021	2022	2023	2024
Company Units	5,383	5,976	6,601	8,923	8,061
Contractor Units	3,799	4,675	3,057	975	997
Company Unit Cost	$9,314	$9,298	$11,334	$12,002	$11,987
Contractor Unit Cost	$9,449	$11,134	$16,585	$26,383	$21,013

Q. What is shown by this comparison?

A. This comparison illustrates that, beginning in 2021 and especially in 2022, contractor costs have increased more quickly than internal costs, although contractor costs decreased significantly in 2024 following a contract renegotiation. Correspondingly, the Company shifted much of the work in this sub-program to internal resources. However, 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 Kelly 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 Security Assessment Inspection Orders.

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 Security Assessment Inspection Orders investment category?

A. Security Assessment Inspection 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 a security 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 8 below.

FIGURE 8
LVD SECURITY 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, creating a clearance or public safety hazard. The line would remain energized but no longer in its safe operating condition.

At times, the Company may quickly address a P1 failure by reducing it to a P2 failure. For example, the Company may address exposed cables in a fiberglass pad by applying a temporary patch; the P1 emergency-level issue will have been fixed, but the pad is still failed and requires replacement. Typically, the Company works to respond to P2 failures within 60 calendar days. However, this time can extend beyond 60 days, such as

when the failed equipment has been bypassed and new equipment is on order for replacement.

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 preemptive identification. 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 Electric Power Research Institute ("EPRI"). Their 2015 technical report, *Distribution Grid Resiliency: Overhead Structures*,[4] 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.

The assessments completed by the Company also identified opportunities to add high-value lateral fusing, and locations where vegetation was an emergent risk of causing an outage. The lateral fusing additions are discussed in the LVD Lines Reliability section of my testimony. The vegetation threats were addressed by the Line Clearing team.

[4] *Distribution Grid Resiliency: Overhead Structures,* https://www.epri.com/research/products/000000003002006780

Q. Please summarize the recent assessments.

A. The Company completed an assessment of 100% of its LVD overhead 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 security assessments?

A. In 2022, the Company identified 6,814 P1 and P2 failures. In 2023, 10,738 P1 and P2 failures were identified. In 2024, the Company identified 10,965 P1 and P2 failures. On average the security assessments have identified one failure for every three miles of line.

Q. Are security assessments the only investment needed to improve SAIDI?

A. No. While correcting failures identified during security assessments mitigates customer outages related to deterioration and other defects, this activity alone is insufficient to improve SAIDI overall. Correction of failures does not enhance the overall system. Rather, it simply corrects the defect at a single point on the system. For example, choosing to replace only one tire on a car when it goes flat would result in four disruptions to travel over time, whereas replacing all four tires upon observing the tread on any one tire is worn away would mitigate travel disruptions due to failed tires. Only focusing on security assessments would be analogous to only replacing the single tire that goes flat; making other proactive reliability assessments is analogous to replacing all four tires at once. Therefore, even when security 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.

Q. What are some examples of failures found in these focused security assessments?

A. The pictures below include examples of P2 failures identified during the assessments in 2024. In the left photo of Figure 9, the lightning arrestor is damaged due to a lightning strike and needs to be replaced. In the right photo of Figure 9, decay and damage at the ground line of a wood pole has greatly undermined the strength of the pole. The left photo of Figure 10 depicts a severely damaged pole, mostly caused by a third party. The right photo of Figure 10 is of a cracked cutout that has fallen off its mount and is being supported by the conductor.

FIGURE 9
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY ASSESSMENTS

FIGURE 10
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY 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 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?

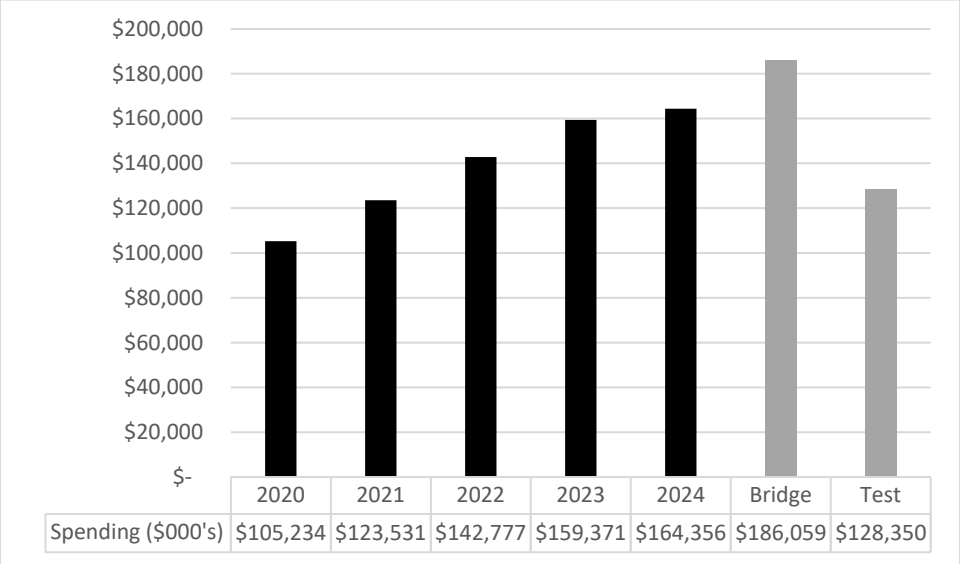
A. This subprogram is essential for the restoration of service to customers for the Company to meet its obligation to serve. Absent investment in this category, customers would remain without electric service because this program funds the basic work necessary to restore electrical service following a failure. Proactive identification of P1 or P2 defects 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 defects 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, and in 2024 it was reduced by 6.2 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 $186,059,000 for the bridge period, and $128,350,000 for the test year, as shown in

Exhibit A-113 (MPK-3), line 32, 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-113 (MPK-3), line 32, and below in Figure 11. Historical spending from 2020 to 2021 in LVD Lines Demand Failures also included the streetlight failure investment category.

FIGURE 11
LVD LINES DEMAND FAILURES SUBPROGRAM EXPENDITURES



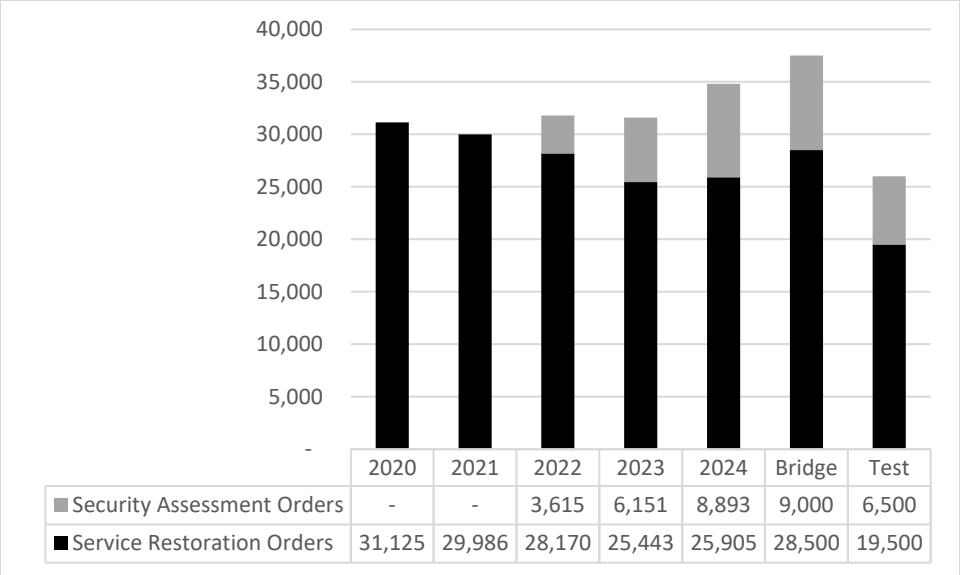
	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$105,234	$123,531	$142,777	$159,371	$164,356	$186,059	$128,350

Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting it will need to complete 37,500 total orders in the bridge period, consisting of 28,500 Service Restoration orders and 9,000 Security Assessment Inspection orders. Within the test period, the Company is projecting it will need to complete 26,000 total orders, consisting of 19,500 Service Restoration orders and 6,500 Security Assessment Inspection orders. The average unit cost for both periods for Service Restoration and Security Assessment orders is $5,300 and $3,900, 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 12 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 12
LVD LINES DEMAND FAILURES UNITS



	2020	2021	2022	2023	2024	Bridge	Test
Security Assessment Orders	-	-	3,615	6,151	8,893	9,000	6,500
Service Restoration Orders	31,125	29,986	28,170	25,443	25,905	28,500	19,500

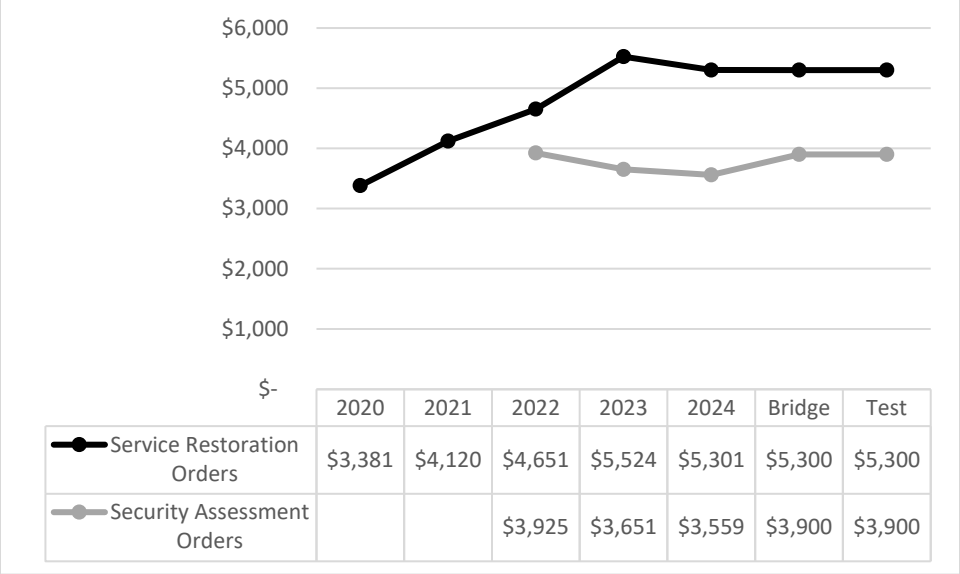
Q. Please explain the year-over-year variation in spending in this subprogram.

A. Spending increases in this subprogram over the past four years have primarily been attributed to unit cost. The four-year average number of orders completed was 31,100.

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 13 below:

FIGURE 13
LVD LINES DEMAND FAILURES UNIT COSTS



	2020	2021	2022	2023	2024	Bridge	Test
Service Restoration Orders	$3,381	$4,120	$4,651	$5,524	$5,301	$5,300	$5,300
Security Assessment Orders			$3,925	$3,651	$3,559	$3,900	$3,900

Q. Please explain any variation in unit costs over time.

A. Service restoration costs can vary due to variations in size and complexity of work orders. The increase in failure unit costs can be attributed to increased material costs as noted in the LVD Lines New Business section of my testimony. The costs of wire, cable, and poles have increased in the last three years. Additionally, the Company's proactive approach to address failures has increased the amount of materials used, and thus time spent, on each of those repairs. For Service Restoration Orders, the Company is projecting the same unit costs for this case ($5,300 per order) that were used to project the costs approved by the Commission in Case No. U-21585.

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 Kelly 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 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 where it is in the 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 may come from the HVD Planning group, the Substation Planning group, or the Metro Planning group, to facilitate projects planned by their respective groups. Most of the requests within the Company consist of requests to relocate LVD underbuild on HVD poles. LVD underbuild refers to LVD assets that are attached to an HVD pole under the HVD lines. When an HVD pole is replaced, the LVD components need to be rebuilt and the conductors need to be transferred to, or replaced on, the new pole.

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 and the latest standards implemented at the time. Relocations performed for HVD or substation work allow maintenance work on the facilities before a failure causes an outage. 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. The LVD Lines Relocation subprogram ensures that municipal requests are completed by the deadline.

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.

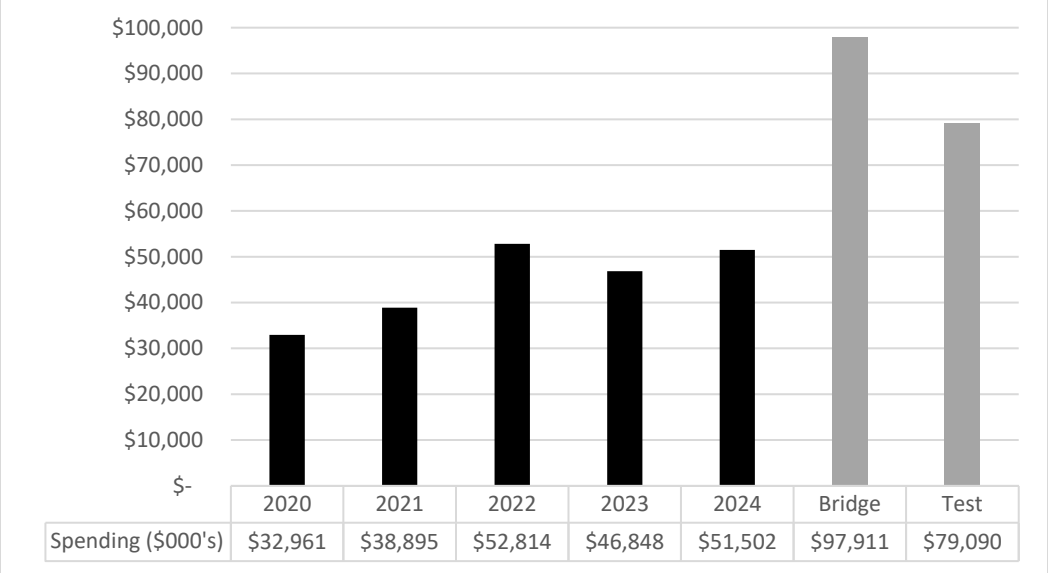
Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Asset Relocations subprogram?

A. The Company has identified known projects for the bridge period and test year, which are listed in Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (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 $97,911,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 38, column (k), and $79,090,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 38, 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-113 (MPK-3), line 38, and below in Figure 14.

FIGURE 14
LVD ASSET RELOCATIONS SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$32,961	$38,895	$52,814	$46,848	$51,502	$97,911	$79,090

Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting that make-ready work will increase in comparison to recent history, especially as telecommunications companies request installation of new cellular and broadband equipment on poles in part driven by federal grants. Increases in spending from 2022 through the test year can be attributed to the 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. In addition to those continuing programs, the application window for Broadband, Equity, Access and Deployment ("BEAD") grant funding is early 2025, and scheduled to start construction in 2026. These programs are expected to influence the LVD Asset Relocations subprogram through 2028. The Company also anticipates continued LVD lines that need 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. In addition, the Company experienced a steady increase in expenditures from third-party and customer requests between 2020 and 2022. The Company anticipates a 1.6% expenditure increase in 2025 to relocate overhead and underground lines and services for the customer requested investment category, as shown in the equation below. These trends informed the Company's projected needs for the bridge period and the test year.

$$Growth\ Rate = \left(\frac{Present}{Past}\right)^{\frac{1}{Years}} - 1 = \left(\frac{25,444,000}{23,527,000}\right)^{\frac{1}{5}} - 1 = 1.6\%$$

The bridge period spending amount for third-party and customer-requested relocations was determined based on recent trends in the number of relocation requests. Like LVD Lines New Business, relocation requests increased by 3.2% from 2020 to 2023. The LVD Underbuild investment category spend was determined based on the projects within the 2024 HVD projected expenditures. Company witness Megan L. Hayward discusses the HVD Lines Reliability projected expenditures.

Q. Can you provide further detail on how the broadband programs discussed above will impact make-ready work?

A. These programs are expected to significantly increase the number of make-ready work orders that the Company will need to complete as part of this sub-program. This increase is shown in Figure 15 below.

FIGURE 15
MAKE-READY FIELD COMPLETE WORK ORDERS BY YEAR

Year	Make-Ready Field Complete Orders
2019 actual	1,007
2020 actual	752
2021 actual	829
2022 actual	1,236
2023 actual	1,655
2024 actual	1,640
2025 Projected	~~5,547~~ 2,689
2026 Projected	~~6,451~~ 3,119
2027 Projected	~~6,816~~ 3,307

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 16 below.

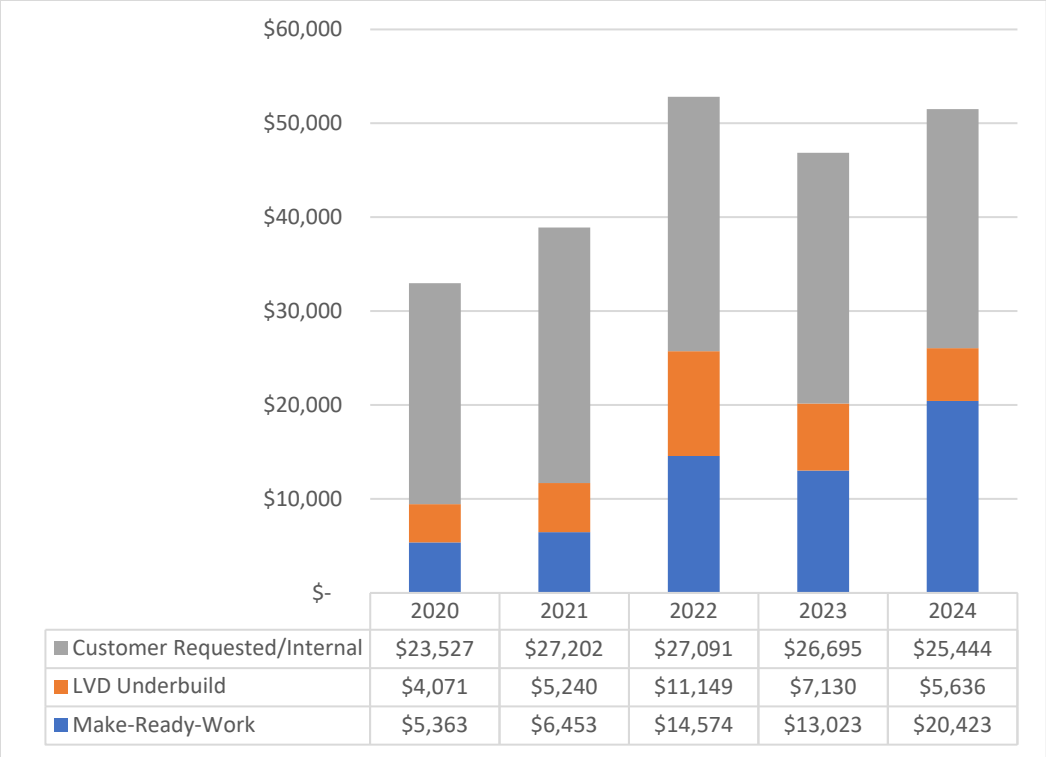
FIGURE 16
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	$45,018,000	4,163	$32,341,000	3,379
LVD underbuild relocations	$7,056,000	N/A	$7,484,000	N/A
Make-ready work	$45,837,000	~~7,697~~ 3,728	$39,265,000	~~6,572~~ 3,181
Total	**$97,911,000**		**$79,090,000**	

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 17 by investment category.

FIGURE 17
LVD ASSET RELOCATION 5-YEAR HISTORY



	2020	2021	2022	2023	2024
Customer Requested/Internal	$23,527	$27,202	$27,091	$26,695	$25,444
LVD Underbuild	$4,071	$5,240	$11,149	$7,130	$5,636
Make-Ready-Work	$5,363	$6,453	$14,574	$13,023	$20,423

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 the years of 2020 and 2021, spending by the telecommunications companies was limited. Starting in 2022, telecommunication companies increased their spending as funds from the *American Rescue Plan Act* and the *Rural Digital Opportunity Fund* became available. Additionally, the Company needed to relocate an increasing number of LVD lines in 2019 and 2022 to accommodate HVD

projects, particularly in locations where LVD lines were underbuilt on HVD structures. The Company saw an increase in customer requested relocations in 2020 and 2021 due to an increase in home remodeling work. The spending continued into 2022 and 2023 but slowed as the interest rates rose at the end of the year.

Q. Does an average unit cost accurately reflect the expected spend 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 as described in the previous response.

Reliability Program

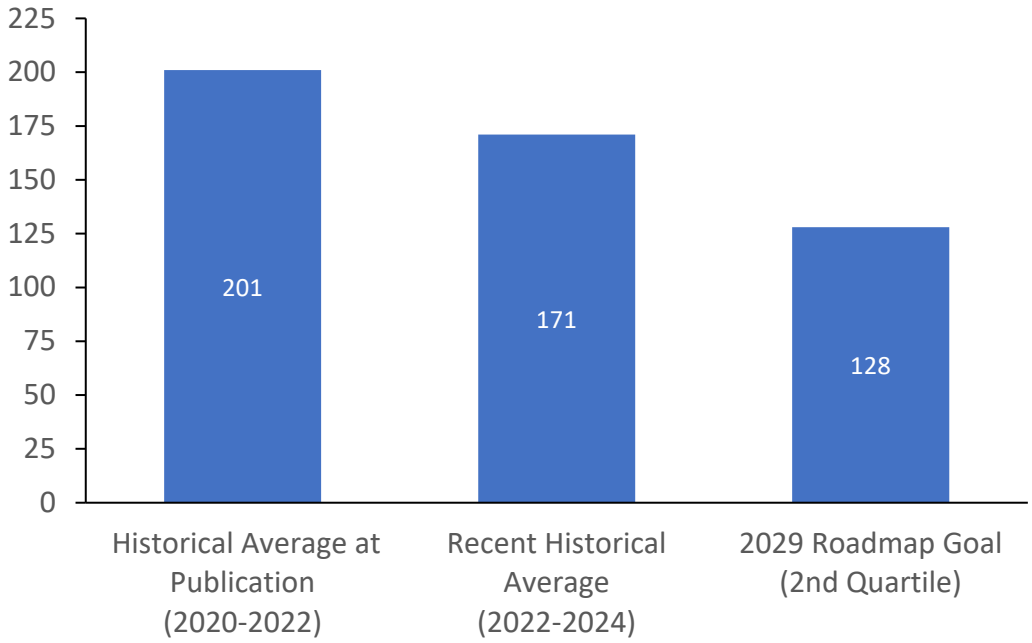
Q. What is the purpose of the Reliability Program?

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 introduced and discussed by Company witness Kelly. As Company witness Kelly explains, 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 increasing investment relative to the historical levels that predated the Reliability Roadmap.

Q. Why is the Company increasing Reliability investment compared to historical levels?

A. As Company witness Kelly discusses in his testimony, 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 Kelly explains that, absent the investment levels identified in the Reliability Roadmap, the Company will not be able to deliver the reliability that both the Commission and various stakeholders have indicated is needed for customers. Specifically, the Company's investments will deliver second quartile reliability performance by the end of the decade, as shown in Figure 18 below.

FIGURE 18
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP Goal



In each section of my testimony on the Reliability Program, I will explain how each investment category is aligned with the investment plan laid out in the Reliability Roadmap, leading to these SAIDI improvements.

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 Kelly. 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, targeted 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, 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

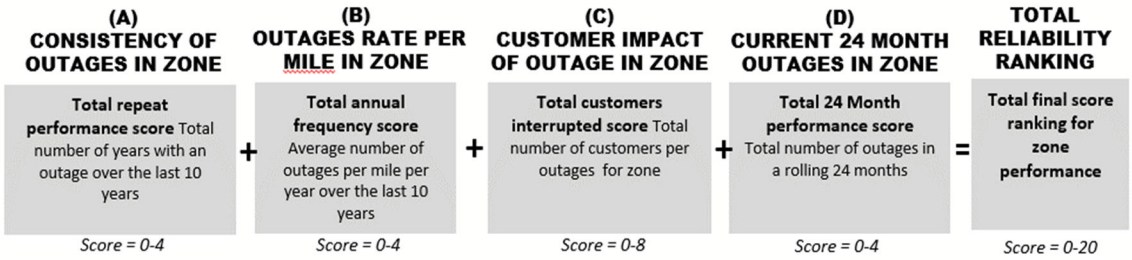
data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps, and calculates the time spent in each step. The RAE also includes 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 19. Once reliability inputs are used to identify zones to target on the LVD system, reliability projects are developed, evaluated, and prioritized to develop an investment plan that maximizes the reliability benefit for customers.

FIGURE 19
ZONAL RANKING FORMULA



Q. Does the Company consider anything besides RAE output when prioritizing projects?

A. The RAE is but 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 projects. The zonal health score considers important factors in prioritizing reliability projects, 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 projects to improve reliability for those customers. 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 to multiplex; and

(iv) rejuvenating vintage underground cable.

The Company has been doing some amount of the kind 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 Kelly. 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

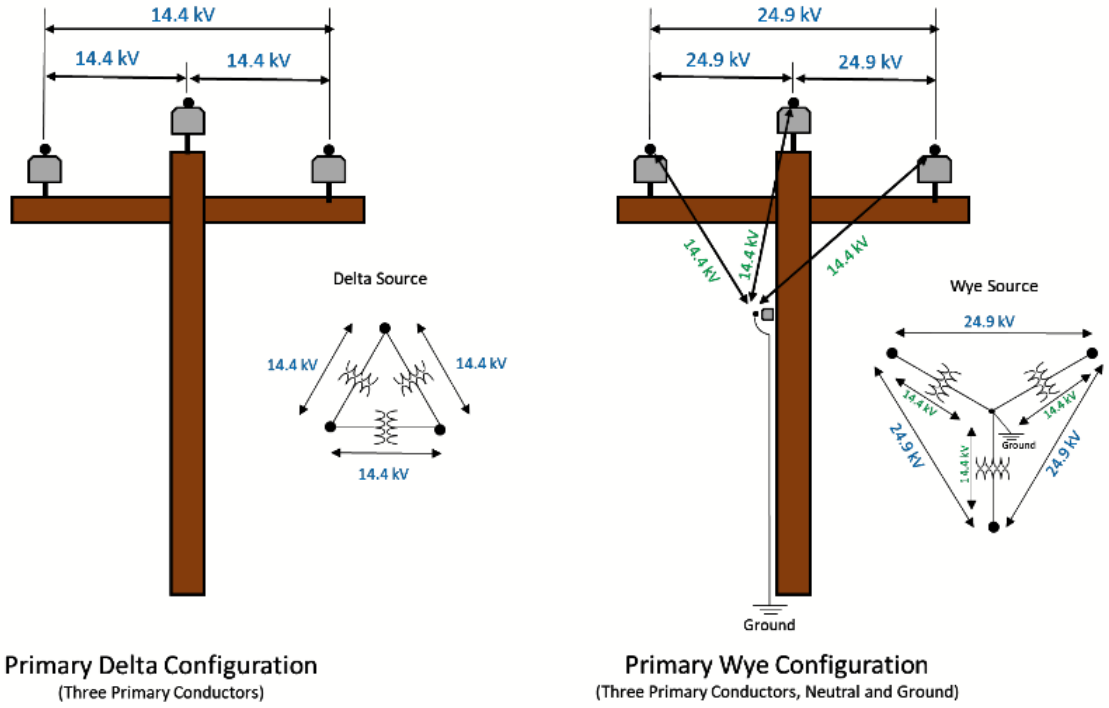
increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the delta system carries (e.g., a 400 Amp rated conductor carrying 360 delta Amps (90% loaded) will carry 208 wye Amps (52% loaded) after the conversion). Since the amount of 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.

- 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 20
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 has shown that 91% of customer interruptions happen on just 25% of line miles. 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 19 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:

- Alger Substation, Skidway Circuit has a zone score of 18. The zone experienced seven outages in 2024. The project will benefit 1,647 customers. This project is to install 336 kcmil aluminum conductor steel reinforced ("ACSR") for one mile to split the load between the Skidway and Forest Lake circuits both on Alger Substation. This will reduce customer counts on one circuit, reduce exposure miles, and allow for future voltage conversion projects for surrounding non-standard voltage substations. This project was selected due to the high Zone Score, 2024 outage count, and the future benefits it can provide to the surrounding substations.

- Camelot Lake Substation, Loomis Circuit, LCP 132 has a zone score of 17. The zone has experienced seven outages in 2024, and one outage as of June 2025. The project is to move 1 mile of line out of deep right of way ("ROW") to the roadside and install tree wire at the new location. The project will benefit 207 customers. The project was selected due to the high zone score, and high outage count.

- Cowan Substation, Ramsdell Circuit has a zone score of 19. The zone experienced two outages in 2024 and two outages as of January 2025. The project is to replace the existing conductor with tree wire for 1.2 miles. The project will benefit 1,386 customers. The project was selected for its high zone score, and consistent outages..

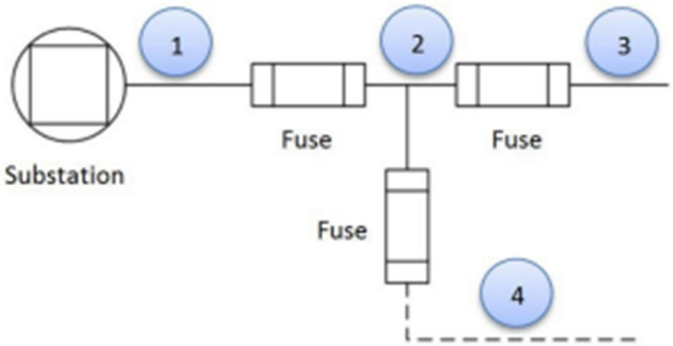
- Frankfort Substation, Gateway Circuit, Zone 5554: This project will reconductor approximately 1,300 feet of #8 copper conductor with #4 ACSR and replace poles to current standards. #8 copper conductor is considered a Hazard Conductor due to its fragility. It easily breaks, especially during storms, and can be hard to splice if it continues to be brittle while crews are handling it. While the zone score for this zone is only 6, the Company is selecting this project due to concerns with the #8 copper conductor. This project will benefit 46 customers.

- The Gilson Substation Rock Lake Circuit Zone 801 project was selected as a voltage conversion project. This zone has 6.8 miles of 11 kVA delta and this project will convert 52 customers to 14.4/24.9 kVA wye. This will eliminate 6.8 miles of non-standard voltage.

Q. Can you provide an illustration of how circuits are subdivided into zones?

A. Yes. Please refer to Figure 21 below, which shows a circuit subdivided into four zones. The Company has approximately 137,000 protective zones on its LVD system.

FIGURE 21
ILLUSTRATION OF DELTA VS. WYE CONFIGURATIONS



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 22 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;

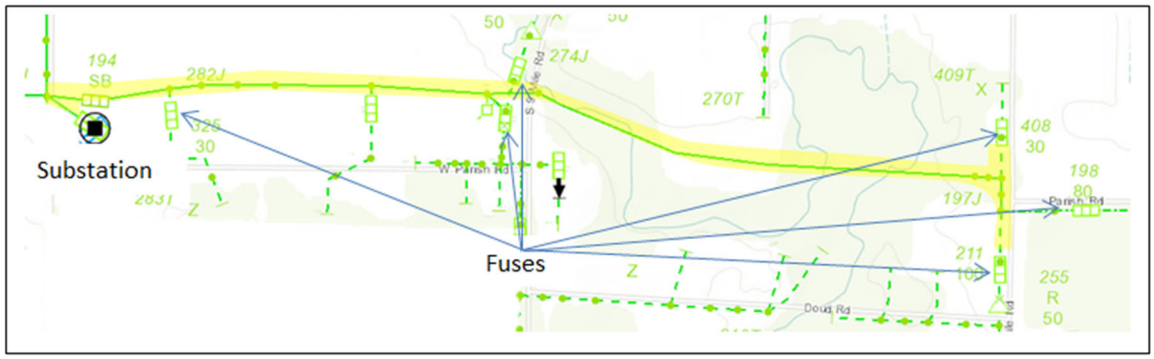
- Restoring underground cable that is no longer looped to re-establish redundancy;

- 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 22
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 completing 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[5], 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." The Company plans to effectively complete this fusing effort in 2025.

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 53% reduction in outages. Figure 23 illustrates zonal performance improvements following targeted circuit improvement projects in 2019 through 2023.

FIGURE 23
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	119	40%
2023	2,884	274	195	28%
Weighted Average Improvement				**53%**

[5] *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 and 2023 in addition to more traditional zonal health improvement work, which is why the number of projects increases by so much. Fusing projects do not necessarily reduce the number of outages on a circuit, but they do reduce the number of customers impacted by any particular outage. This impacts the before and after outage numbers in the figure, and therefore the calculated percentage improvement. 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.

Q. Please provide some specific examples of recent zonal health improvement projects.

A. Recent examples of these projects include:

- The overhead conductor on Cedar Springs Substation, Nelson Circuit, Zone 150, was faulting two to three times per year between 2015 and 2021, with four outages in 2020. A majority of the outages were caused by trees on blue sky days and during storms. Each outage caused interruptions to 454 customers. In June 2022 the overhead conductor was replaced with tree wire to prevent outages. This zone has not caused an outage since March 2022. Between 2022 and 2025, this has saved approximately 177,000 customer-outage-minutes annually.

- The overhead conductor on Foreman Substation, Cumberland Circuit Zone 646, had two to five outages every year between 2015 and 2020, with another four outages in 2022 averaging 62,500 customer-outage-minutes annually. The causes were trees, inside and outside of ROW, and storms affecting 96 customers. In April 2023, the Company installed 0.8 miles of tree wire to minimize the tree related outages. These customers have not experienced an outage originating in this zone since the project's completion.

- The underground cable on Calvin Substation, Rosemont Circuit, Zone 654, was faulting once each year from 2015 through 2017, interrupting approximately 30 customers. This underground section was selected for underground rejuvenation to inject the cable and replaced segments of cable in 2018 and 2019. Subsequently, those customers experienced no interruptions in 2018

through 2023 due to this issue, saving approximately 43,000 annual customer-outage-minutes.

- Alamo Substation, Pine Grove Circuit, Zone 844, experienced three outages in 2021 and five outages in 2022, mainly due to tree issues, interrupting approximately 1,030 customers. In 2024, the Company upgraded a section of three-phase conductor to tree wire in an area that has lots of tree overhang. Shortly after this project was constructed, a large tree fell on the new tree wire. The tree wire held up the tree, subsequently saving approximately 227,300 customer-outage-minutes. The photo in Figure 24 below shows the tree being supported by the new tree-wire.

FIGURE 24
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 and 6.5 minutes in 2024. Continued addition of lateral fuses in 2025 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, as Company witness Kelly explains in his direct testimony, the Company is adjusting this plan to maintain the same SAIDI glidepath while accounting for increased line clearing work, and the Company is now only ramping up to 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). This change is reflected in the test year projections for zonal health investments in the instant case. In every instance, the Company is planning projects in zones that have been specifically identified as needing investment to deal with reliability issues.

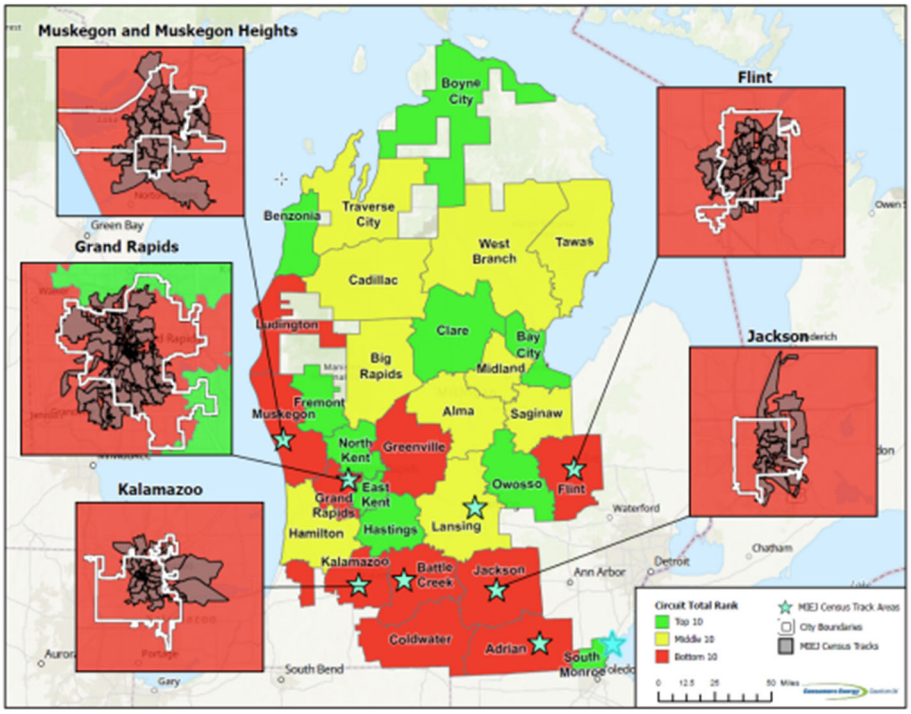
Converting Open-Wire Secondary to Multiplex

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 25 below, open-wire secondary has a disproportionately high impact on vulnerable communities.

FIGURE 25
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-166 (JMP-1), page 12; and in Exhibit A-167 (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's proposed investments in the instant case are in line with this approved level. The Company's planned investments in the instant case focus heavily on vulnerable communities first; following the Commission's disallowances for these investments in Case No. U-21585, the Company is prioritizing using the remaining dollars to invest in those communities. The difference between open-wire secondary and multiplex secondary is shown in Figure 26 below.

FIGURE 26
MULTIPLEX VS. OPEN WIRE SECONDARY

Q. How does this conversion work benefit customers?

A. The most important benefit of doing this will be 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 cable is 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 27 below illustrates the locations of this 15 kV vintage underground cable, along with locations of outages over the past three years. Figure 28 illustrates the SAIDI contribution of the underground system, highlighting that the most critical areas are in Grand Rapids, Flint, Traverse City, and Kalamazoo.

FIGURE 27
UNDERGROUND CABLE: LOCATIONS OF 15 KV CABLE

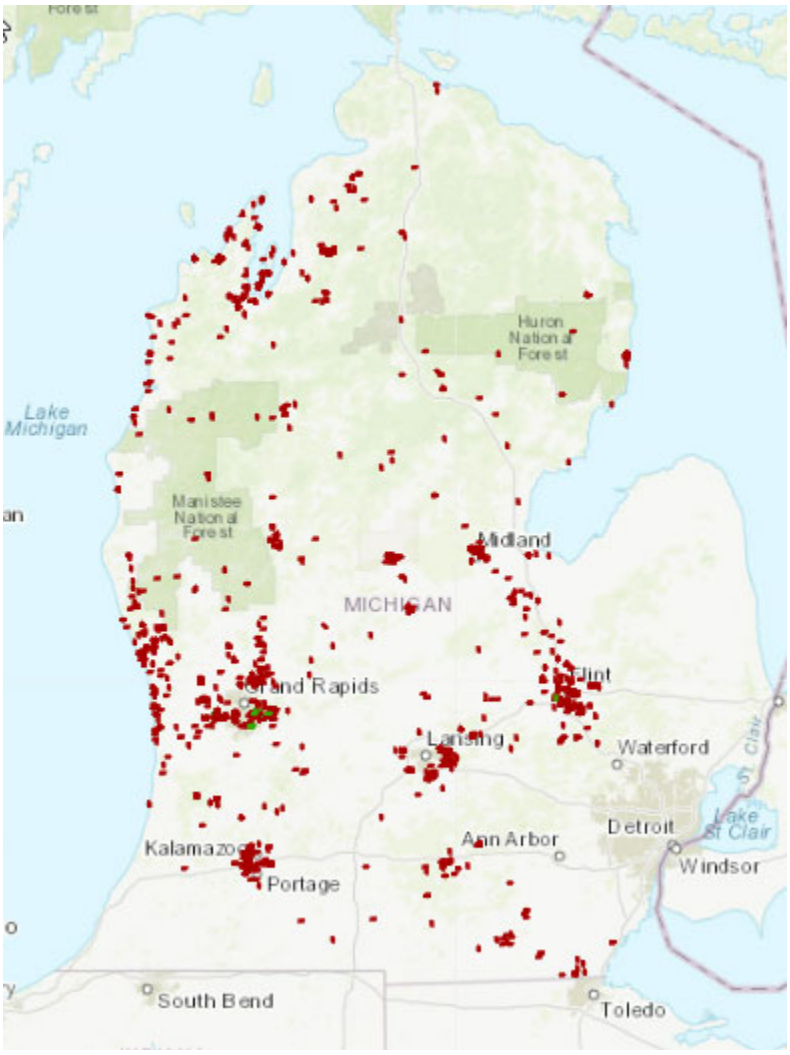
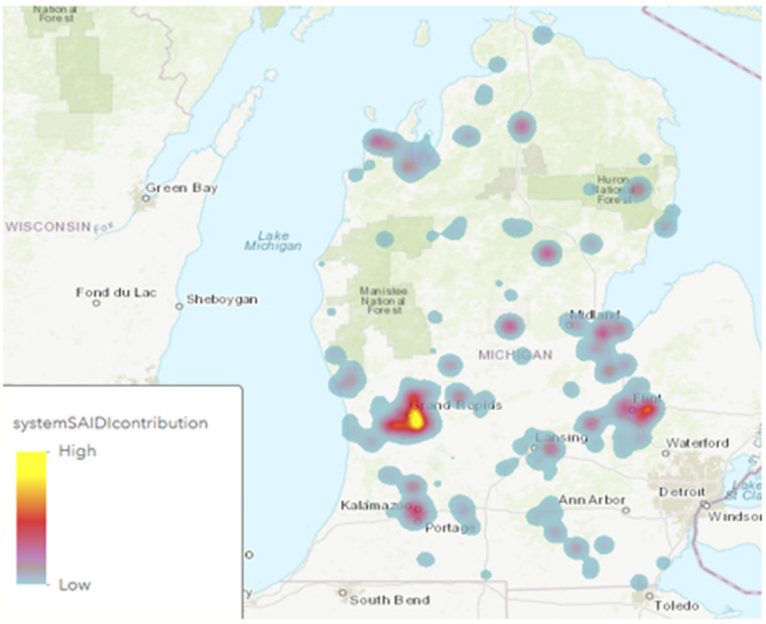


FIGURE 28
SAIDI CONTRIBUTION OF UNDERGROUND PRIMARY



Q. How does the Company plan to address these concerns?

A. To address these challenges and ensure that existing undergrounded lines continue providing resiliency for customers, the Company has begun using cable injection to rejuvenate the underground cable. This innovative process involves injecting a fluid insulation into the cable that then solidifies. This is less expensive than completely replacing the cable and is expected to extend cable life by a minimum of 25 additional years. Initially, the Company concentrated these investments in Grand Rapids and Flint because it has been most cost-effective for contractors to complete all work in one area before moving on to new locations. The Company will begin working in Traverse City as well in 2026. As explained in the Reliability Roadmap, the Company plans to rejuvenate all 15 kV cable installed between the 1960s and 1980s, over a period of nine years beginning in 2025, with a ramp-up to investing up to $165 million each year.

It is notable that Liberty's distribution system audit highlighted the successes of vintage underground cable rejuvenation. Specifically, they wrote, "Consumers has had success to date in using rejuvenation, supported by long-term guarantees of effective operation by the contractor who performs the work." Liberty concluded that this work "reflects a sound means for addressing vintage underground cable reliability problems."[6]

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. Pole replacements in the LVD Lines Reliability subprogram are completed based on two primary types of inputs. First, poles are replaced in response to prior inspection results from previous years that identified poles at risk of failure. The Company evaluates the results of those pole inspections to determine if a simple pole replacement is required, and further evaluates inspection results to determine if an entire pole line should be replaced or relocated to improve reliability. The Company has had a backlog of poles identified in previous years' inspections for some time, and has been working through this backlog through pole replacement projects each year.

Second, following the development of the Reliability Roadmap the Company is starting a program of groundline inspection of poles.

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. While these inspections are underway,

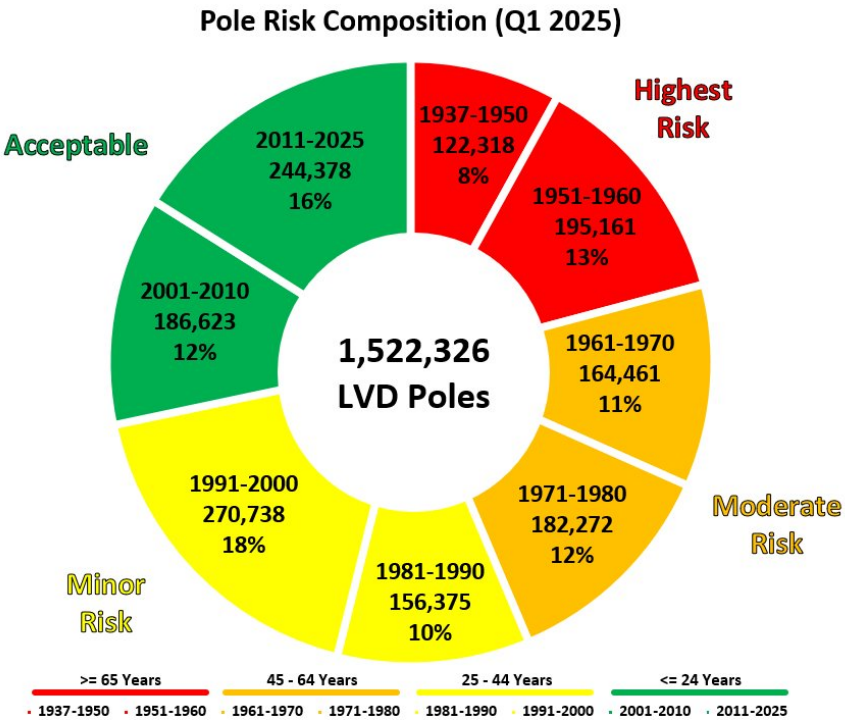
[6] Liberty Final Report Part Two, pg. 69, September 23, 2024 in Case No. U-21305

the Company will continue to replace LVD poles identified in inspections that have not yet been completed, as described above. Based on system data, the Company estimates that approximately 10% of the poles on the LVD system will be classified as rejected based on these inspections, and the Company therefore projects that these inspections will identify 12,500 LVD poles per year for replacement. This anticipated rejection rate is 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. A breakdown of the Company's pole vintage is shown in Figure 29 and a breakdown of LVD pole risk is shown in Figure 30. 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 29
LVD POLE VINTAGE BREAKDOWN

Vintage	Count	Percentage
2001-2025	431,001	28.31%
1981-2000	427,113	28.06%
1961-1980	346,733	22.78%
1960 and older	317,479	20.85%

FIGURE 30
LVD POLE RISK BREAKDOWN – Q1 2024



Regardless of how a pole was identified as being in need of replacement, 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 major public safety hazard, threatening both people and property. Furthermore, poles in poor asset health present major safety hazards for lineworkers who may need to climb the pole during restoration work, particularly if the pole gives way under the lineworker'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.

Q. Is the Company taking any other actions to improve LVD poles?

A. Yes. As discussed on page 70 of the Reliability Roadmap, over time the Company has upgraded its minimum pole standards for the LVD primary system from Class 6 to Class 3. As the Company replaces poles, it is installing poles that meet the new standard. These larger Class 3 poles can endure wind gusts of up to 141 MPH without ice, or up to 71 MPH when there is a half-inch of radial icing thickness. The Company no longer uses any Class 5 or Class 6 poles in new construction or when replacing existing poles during storm restoration. Furthermore, the Company began installing ductile iron poles as an alternative to wood poles starting in 2024 for targeted locations. The ductile iron poles to be installed are an equivalent to a Class 1 wood pole and will have a longer design life in comparison to wood poles.

The difference in pole class capacities is shown in Figure 31 below. Improved pole standards improve resiliency because poles are most challenged by external forces leading to failure during severe weather rather than on blue-sky days.

FIGURE 31
2023 NESC CODE[7]

No Significant Pole Deterioration as Noted in NESC Table 261-1			
NESC Grade C Construction - LVD - NESC 250C&D Load Factors			
Pole Size Minimum	No ICE, Max Wind Speed Prior to Failure (mph)	½ Inch Ice, Wind Speed Prior to Failure (mph)	1 Inch Ice, Wind Speed Prior to Failure (mph)
Class 6	109 mph	54 mph	39 mph
Class 5	116 mph	57 mph	43 mph
Class 4	129 mph	64 mph	49 mph
Class 3	141 mph	71 mph	54 mph
Class 2	157 mph	79 mph	60 mph
Class 1	170 mph	86 mph	67 mph

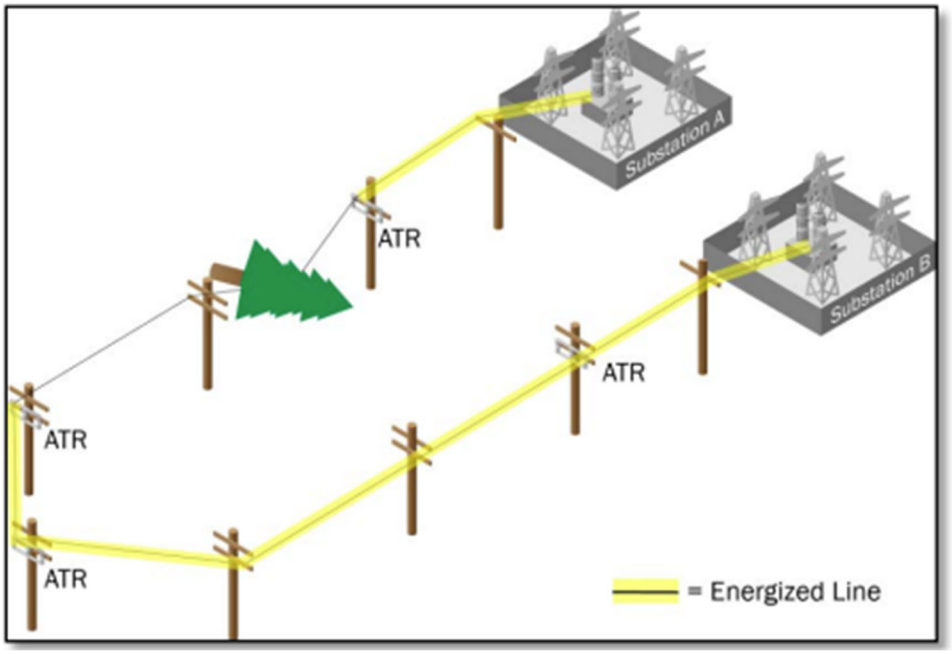
ATR Loops

Q. What are Automation Transfer Recloser ("ATR") Loops?

A. As discussed, beginning on page 81 of 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 32 below shows how ATRs maintain power for a large part of the system following an incident that would have caused more interruptions to customers.

[7] 2023 NESC, linear analysis, 1/0 ASCR 3 phase conductor with #4 ACSR Neutral, 350-foot spans, 45-foot pole lengths.

FIGURE 32
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 has moved this work into the LVD Lines Reliability subprogram because it is now a 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 March 2023, there were 154 ATR Loops in service providing over 216,000 customers with a self-healing smart grid that prevents or minimizes the impacts of outages. Figure 33 shows the previous five years of tabulated actual benefits.

FIGURE 33
ATR LOOP HISTORICAL RELIABILITY BENEFITS

Year	Customer-Outages Prevented	Customer-Outage-Minutes Avoided
2019	34,333	10,334,000
2020	33,172	9,131,000
2021	36,098	23,375,000
2022	63,359	18,222,000
2023	69,339	18,059,000
Total	**236,301**	**79,121,000**

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.

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

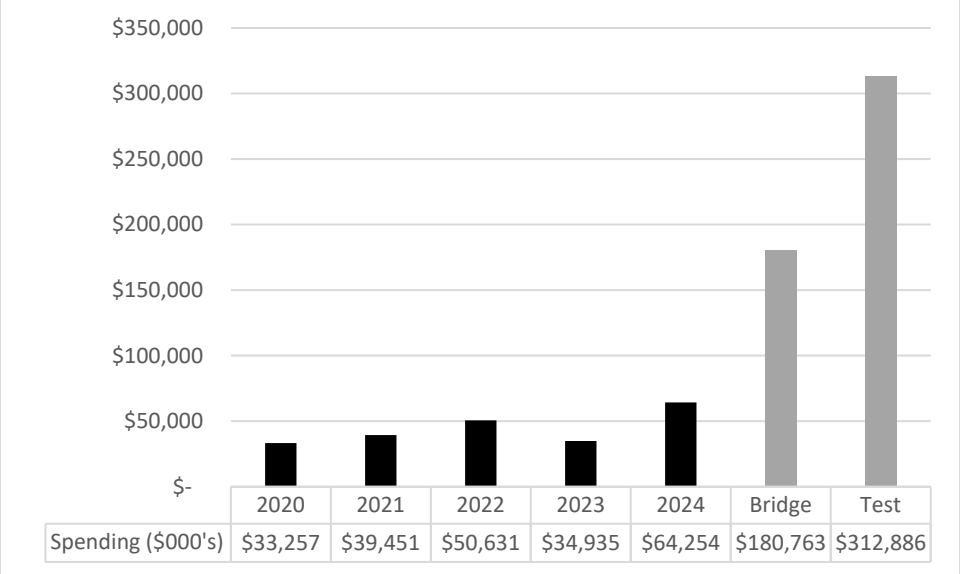
enabling LVD line projects across multiple capital subprograms. These projects are critical to prepare for LVD construction and adequately support the project that is depending on the new rights. New rights are required for new LVD line, LVD line relocation or rebuild off-center, and improved easements 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.

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 $180,763,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 7, column (k), and $312,886,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 7, 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-113 (MPK-3), line 7, and below in Figure 34.

FIGURE 34
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 Resilient Grid Plan that is defined in the Reliability Roadmap. The large increases in investment in this subprogram are mostly driven by increased investments in zonal health improvements and pole replacements. As the Reliability Roadmap makes clear, significant investment is needed in improving LVD zonal health and replacing LVD poles to deliver better reliability for customers, while managing the challenges of increasingly severe weather. With 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, these investments are necessary to achieve the Company's glidepath for reducing SAIDI.

Increased investment in this subprogram is also being driven by new investments in voltage conversions and open-wire secondary conversions to multiplex which will

deliver other non-reliability benefits to customers, particularly in vulnerable communities. In the bridge period and test year, there are over 35 miles of open-wire secondary conversions and 20 miles of zonal health improvements identified on circuits serving 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 35 below.

FIGURE 35

LVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Targeted Circuit Improvement *strategies:*				
• Zonal Health Improvements	$61,320,000	497*	$34,917,000	175*
• Secondary	$19,680,000	66	$14,670,000	49
• Voltage Conversions	$8,427,000	44	$33,115,000	283
• Underground Cable Rejuvenation	$27,909,000	68	$65,989,000	158
ATR Loops	~~$17,539,000~~ $25,616,000	~~39~~ 59	~~$22,299,000~~ $15,412,000	~~40~~ 33
Pole Replacements	$29,711,000	3,076	$127,500,000	12,500
Circuit Exit Projects	$1,911,000	84	$3,616,000	197
Right-of-way	$6,188,000		$17,667,000	
Total	**$180,763,000**		**$312,886,000**	

*Units for Zonal Health Improvements represent total number of projects; individual projects have varying types of units as shown in Exhibits A-166 (JMP-1) and A-167 (JMP-2).

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-166 (JMP-1), pages 2 through 14, and for the test year, listed in Exhibit A-167 (JMP-2), pages 2 through 10. 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 34 above for zonal health improvements?

A. Zonal health improvements involve multiple types of projects, and it is difficult to summarize them with a single kind of unit in this figure. Some zonal health improvement projects involve addressing a certain number of line miles on a circuit, while others involve installing a certain number of fuses, and for some the applicable unit is simply "1 project." These details are reflected in Exhibits A-166 (JMP-1) and A-167 (JMP-2). Figure 34 simply lists the total number of line items for zonal health improvements in those exhibits.

Q. What are the different types of pole replacement projects listed in Exhibits A-166 (JMP-1) and A-167 (JMP-2)?

A. As discussed above, the Company has two different types of pole replacement work: projects to replace poles identified in prior years' inspections, and projects to replace poles identified during the Company's new groundline inspection program. In Exhibit A-166 (JMP-1), page 2, the Company has listed a number of pole replacement projects of the first type. Additionally, Exhibit A-166 (JMP-1), page 2, line 21, indicates that the Company projects to replace 1,700 poles in response to groundline inspections during the bridge

period. Exhibit A-167 (JMP-2), page 6, line 24, indicates that the Company projects to replace 12,750 poles in the test year in response to 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 Resilient Grid Plan, as described in the Reliability Roadmap, and by Company witness Kelly's testimony. 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-166 (JMP-1), pages 2 through 14, and A-167 (JMP-2), pages 2 through 10. Types of benefits identified on the exhibits, and summarized in Figure 36, 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 36
LVD LINES RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	382,538,000	36,180,590
Customers impacted	16,103	43,850
Increase Safety by Installing Isolation Point at Sub	84	197

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 37. There are no unit costs for the ROW investment category because units are not identified for this work.

FIGURE 37
LVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024
Targeted circuit improvements	$108,488 /project	$112,093 /project	$3,986 /project	$3,498 /project	$35,315 /project
Pole replacements	$8,357 /pole	$10,047 /pole	$14,738 /pole	$13,831 /pole	$5,758 /~~project~~ pole
Circuit exit enhancements	$33,696 /project	$43,658 /project	$51,993 /project	$46,842 /project	$31,147 /project
ATR Loops	$571,778 /loop	$668,319 /loop	$440,805 /loop	$462,945 /loop	$423,990 /loop

Q. Please explain any variation in unit costs over time.

A. Pole replacement unit costs increased in 2021 because Consumers Energy increased the standard for pole class size for added reliability, added resiliency, and to align with industry best practices. Increasing the Company's standard pole class size provides additional strength to the system for projects taking place across the electric service territory. Pole replacements take on average three to four hours to replace.

Replacement with increased sized poles, as part of upgrading to a higher pole class as discussed above, helps prevent the pole from breaking during an event such as a tree falling on the line. In the situation with a tree falling on a line, other weaker components will fail such as crossarms, braces, etc. The repair time for pole top components such as insulators and crossarms is substantially less than replacement of a pole that requires MISS

DIG notification and associated wait periods. The increase in pole class size impacts the cost of the pole ranging from $50 to $250 depending on class and height. Individual projects for targeted circuit 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 cost for 2022 and 2023 for this investment category is less than prior years and less than in 2024. The unit cost for ATR Loops for 2022 and 2023 was lower than prior years because the Company completed some upgrades of existing loops, which have a lower cost, and focused its efforts on identifying lower cost loop projects. These lower cost loops avoided major LVD line upgrades for the new loops while maximizing benefit-cost ratios.

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 in 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. Investments in this program address issues of frequent interruptions primarily by targeting specific zones for improvements.

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. In its final Order in Case No. U-21585, the Commission noted that the Company's 2023 performance on CEMI-4+ was too high, which warranted the Company's planned investment in this sub-program. When considering the 2024 CEMI-4+ results as well, it is clear to the Company that it must dedicate more focus to this sub-program in order to bring CEMI-4+ levels down to a more acceptable level. Additionally, the Commission has added a CEMI metric to its new financial incentives and disincentives mechanism in Case No. U-21400, providing further guidance that the Company must strive to address CEMI.

In order to meet the Commission's standards and expectations, increased investment is needed for preventing repetitive outages.

Q. How does the Company plan to address this concern?

A. The Company plans to increase investment in the Repetitive Outages sub-program to ensure it will achieve the Service Quality and Reliability Standard of 6% in the future. As described by Company witness Kelly, the Company is projecting a CEMI-4 of 8.2% in 2026 based upon the overall investment plan as approved by the Commission in Case No. U-21585. The Company needs to spend an additional $33.2 million in 2026 and $23.0 million in 2027 to achieve the standard beyond 2026, which is reflected in the Company's projected bridge period and test year investment levels in the instant case.

Q. How did the Company determine the needed scale of increased investment?

A. On average, it requires $90,000 in investment to improve a zone that impacts 118 customers with repetitive outages. To mitigate repetitive outages for each 1% of customers for which CEMI performance is short of the Commission's standard, the Company will have to address 161 zones at the cost of $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 and improved restoration time;

- 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 Kelly, in the Historical System Performance section of his testimony, 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 Outage 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 improve 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-166 (JMP-1), pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16 are consolidated into Figure 38 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 38
REPETITIVE OUTAGE BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	14,678,557	13,307,890

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 19—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.

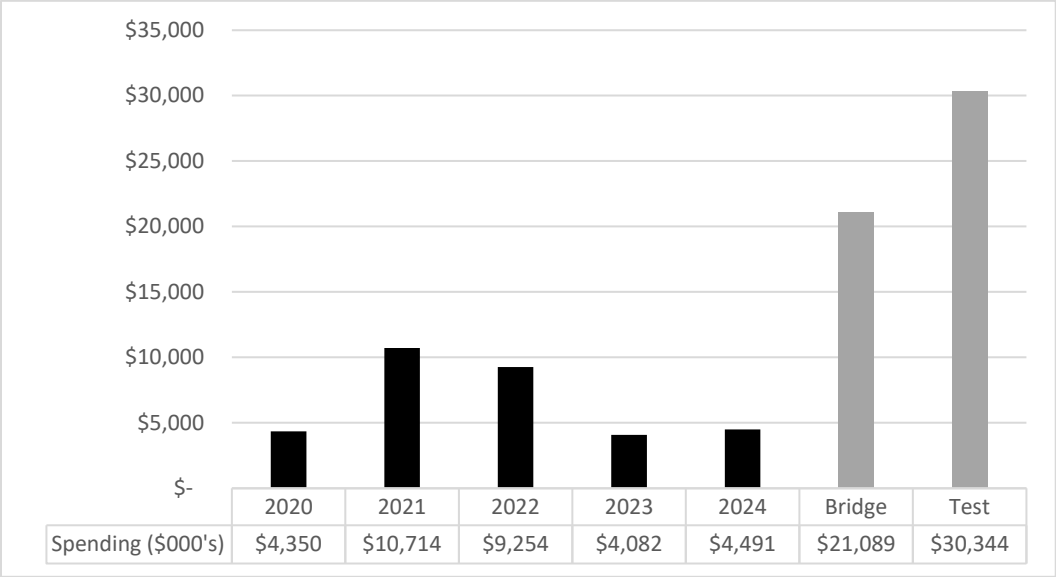
In addition to using RAE data, the Company focuses on customers experiencing CEMI-4+ and prioritizes them for projects in this subprogram, even if they might not have otherwise been considered for investment prioritization in the LVD Lines Reliability subprogram.

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 $21,089,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 12, column (k), and $30,344,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 12, column (l). The Company is planning to complete 246 projects in the bridge period and 337 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-113 (MPK-3), line 12, and below in Figure 39.

FIGURE 39
LVD REPETITIVE OUTAGES SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$4,350	$10,714	$9,254	$4,082	$4,491	$21,089	$30,344

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-166 (JMP-1), pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16. The Company developed the projected costs of the projects in the exhibit considering typical costs for materials and labor, and the Company's previous experience performing similar projects. This exhibit also identifies the location and benefits of the projects. While projects for the bridge period 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 expensive, 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. The purpose of increasing investment in this case from 2024 levels 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 final Order in Case No. U-21585, the Commission directed the Company to show that these dollars were spent on addressing reliability in LVD repetitive outages in this sub-program. What are you presenting in response to this direction?

A. Please refer to Exhibit A-169 (JMP-4). This exhibit identifies all of the projects in the LVD Repetitive Outages sub-program that had substantive investment in 2023 and/or 2024, and shows how many outages occurred both before and after work was completed. In reviewing this exhibit, it is important to note that the total dollars for each year does not exactly match the historical investment levels shown in Exhibit A-113 (MPK-3). In a given year, all sub-programs include some costs and some accounting credits related to closing

out prior year projects. As noted above, the purpose of Exhibit A-169 (JMP-4) is to show projects that had substantive investment in the years in question.

As has already been stated, the Company did invest less in LVD Repetitive Outages in 2023 and 2024 than in some other recent years, for reasons already discussed. However, the money that was invested in LVD Repetitive Outages in those years did go toward repetitive outage projects.

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 four investment categories:

(i) imminent rehabilitation;

(ii) meter voltage anomalies;

(iii) subsurface transformer replacements; and

(iv) modem replacement program.

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 is being newly defined in the instant case, based on voltage anomalies that the Company has recently begun to identify using its 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.

Q. Has this subprogram historically included any other investment categories?

A. Yes. Prior to 2024, this subprogram included an investment category called Security Assessment Repairs. As the Company initially explained in Case No. U-21389, that work will now be 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 40 presents the types of hazards classified as P3 and P4. The hazards are listed by the priority code for the anomaly.

FIGURE 40
LVD SECURITY 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 no immediate need for repair as there would be with 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 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.

Q. Please explain the subsurface transformer replacement investment category.

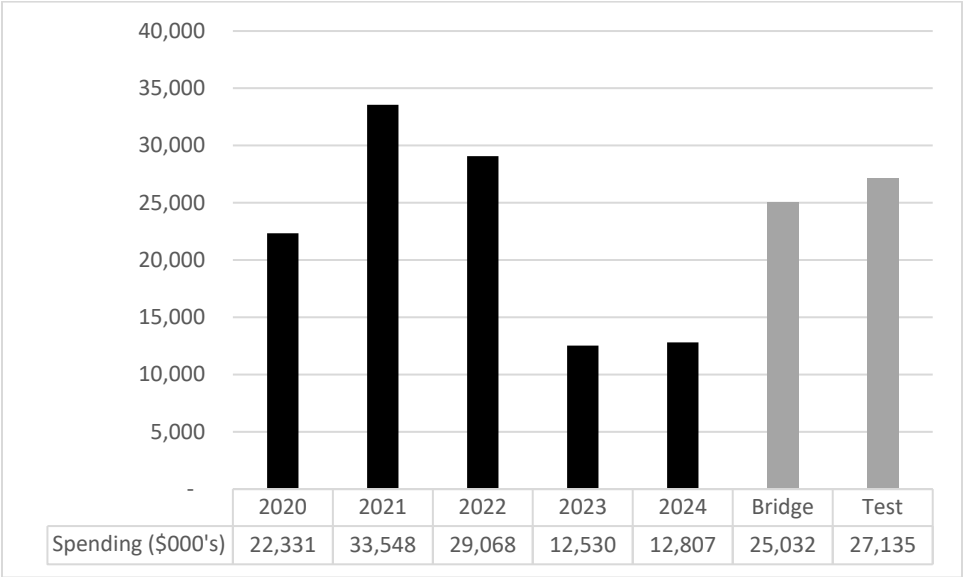
A. As discussed, starting on page 60 of the Reliability Roadmap, the Company's underground system has 159 of its original subsurface transformers still installed. These transformers

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 2027.

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 $25,032,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 17, column (k), and $27,135,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 17, 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-113 (MPK-3), line 17, and below in Figure 41.

FIGURE 41
LVD LINES REHABILITATION SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	22,331	33,548	29,068	12,530	12,807	25,032	27,135

Q. How did the Company develop its projected expenditures in this subprogram?

A. While the Company now addresses security 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. The bridge period and test year also include the newer investment categories for modem replacements and subsurface transformer replacements as discussed, and the new investment category for meter voltage anomalies. 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 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 42.

FIGURE 42
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	$15,120,000	442	$9,413,000	165
Subsurface transformers	$528,000	15	$3,181,000	54
Modem Replacement Program	$2,998,000	800	$2,988,000	800
Meter Voltage Anomalies	$6,386,000	N/A	$11,553,000	N/A
Total	**$25,032,000**		**$27,135,000**	

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-166 (JMP-1), pages 15 through 22, and for the test year, listed in Exhibit A-167 (JMP-2), pages 17 through 20. 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 Company only has five

total subsurface transformer projects in the test year, but this is due to one large project replacing many subsurface transformers in a subdivision.

Q. Please explain the year-over-year variation in spending in this subprogram.

A. In 2021, the Company addressed P3 and P4 deteriorated system assets identified in security assessments and imminent rehabilitation. That increase over 2020 enabled the completion of the circuits with previously completed security assessments. Material delivery challenges in 2022 inhibited work in other subprograms resulting in crews completing more imminent rehabilitation work which used materials that were more available.

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-166 (JMP-1), pages 15 through 22, and A-167 (JMP-2), pages 17 through 20.

Q. Please explain why some of the imminent rehabilitation projects in the LVD Lines Rehabilitation subprogram have similar customer benefits.

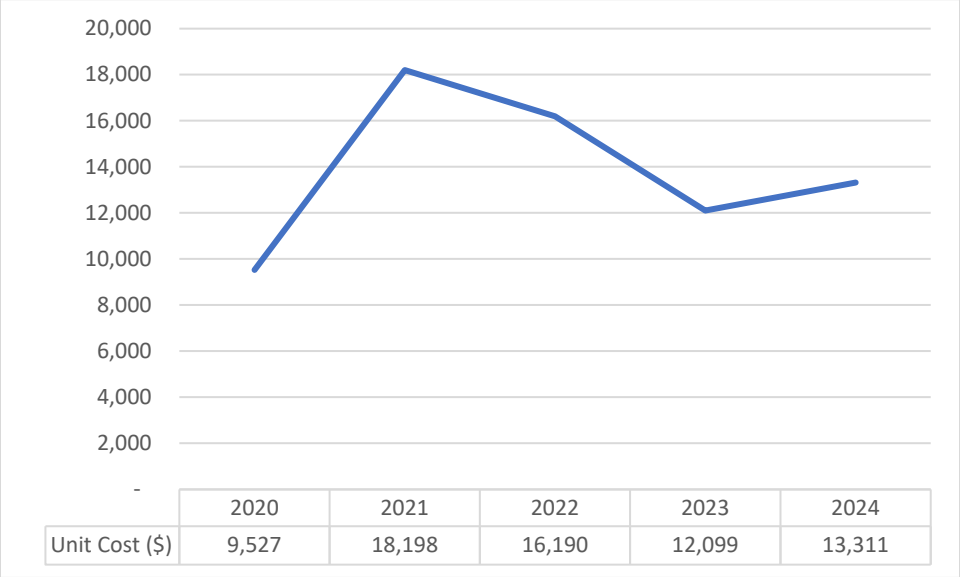
A. The work required for many of these projects is similar in nature and therefore some projects are estimated to have similar benefits based on the reported finding and historical orders of the same type. To improve secondary voltage for customers, it typically requires

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 43 below.

FIGURE 43
LVD LINES REHABILITATION INVESTMENT CATEGORY UNIT COSTS



	2020	2021	2022	2023	2024
Unit Cost ($)	9,527	18,198	16,190	12,099	13,311

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. In 2019, projects considered deterioration were being charged to imminent rehabilitation. Primarily, this work included replacement of overhead or underground deteriorated primary and secondary conductors over multiple spans due to frequent wire downs. In 2020, these projects were redefined to be zonal health projects, as described in the LVD Lines Reliability portion of my testimony. In 2021 and 2022, the scope of the work required on imminent rehabilitation was more extensive than that required in other years.

For example, in 2021, more underground work was completed than overhead and there were more locations completed per order.

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 $2,100,000 per project. However, because there is a reasonable volume of units an average unit cost could be used to analyze the projections for the overall subprogram, but not the cost of any individual project.

Resiliency

Q. What is the purpose of the Resiliency subprogram?

A. As described by Company witness Kelly and 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 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 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. Why does the Company have 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. One of the recent events in August 2021 was a multi-day storm with 70 mile-per-hour wind gusts that 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. 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 and led to new proposals targeting resiliency in the Company's 2022 rate case in Case No. U-21224, which were further expanded in Case No. U-21389 in 2023. 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. The project list exhibits also include projects for the Vulnerable Communities Resiliency Plan that is

primarily discussed by Company witness Kelly, because these projects are primarily intended to increase resiliency in the targeted communities. The project list exhibits also include work related to underground services and make secondary improvements in disadvantaged communities ("DACs") under a grant from the Michigan Department of Environment, Great Lakes, and Energy ("EGLE"). 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, the Company will be able to:

i. complete twelve new circuits at seven existing substations;

ii. complete one new substation with four new circuits; and

iii. complete purchase order milestone payments for one new mobile substation.

The mobile substation will support construction of the additional substation projects proposed in this subprogram, avoiding customer outages that would have otherwise been required.

FIGURE 44
FRACTIONALIZATION OF A SUBSTATION

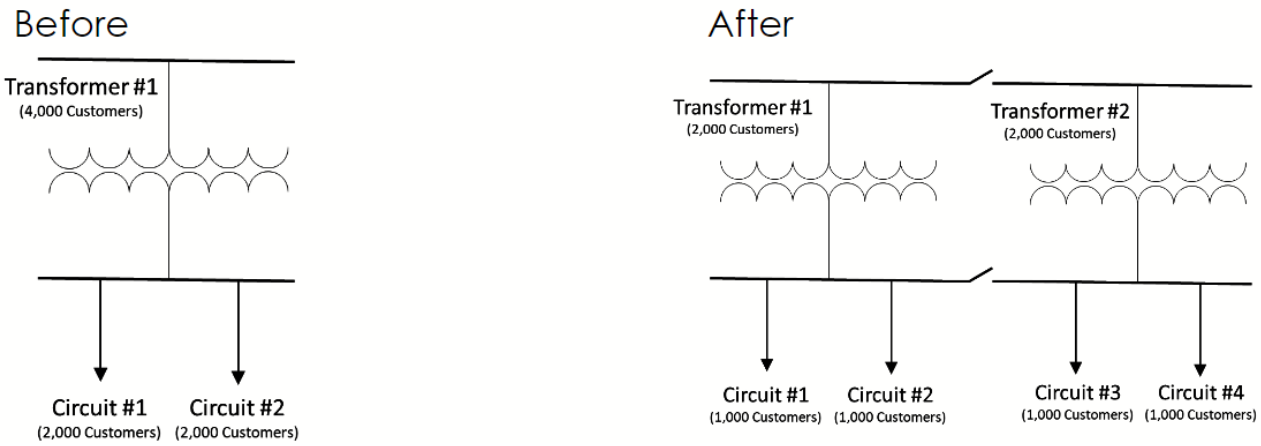
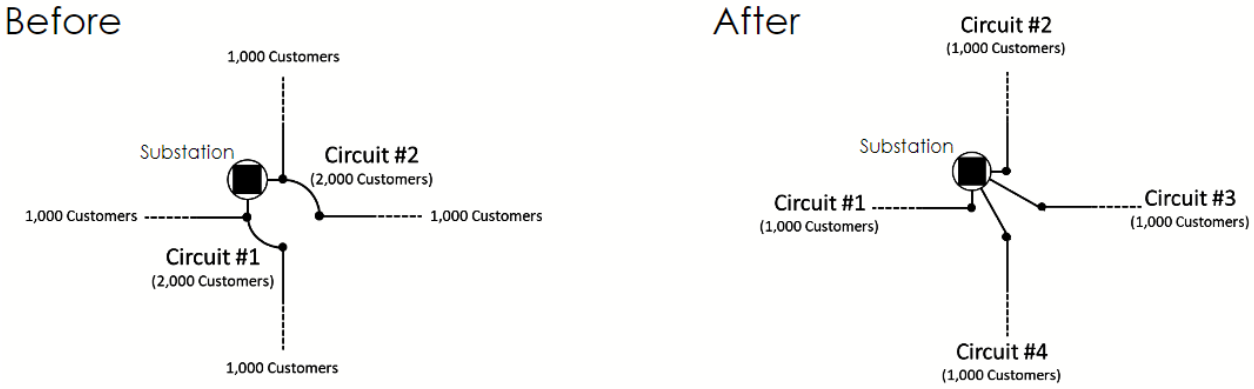


FIGURE 45
FRACTIONALIZATION OF LVD CIRCUITS



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 46 and Figure 47, there is a small percentage of circuits that are outliers with respect to customers served and miles of overhead line exposure.

FIGURE 46
CIRCUITS RANKED BY OVERHEAD PRIMARY LINE EXPOSURE

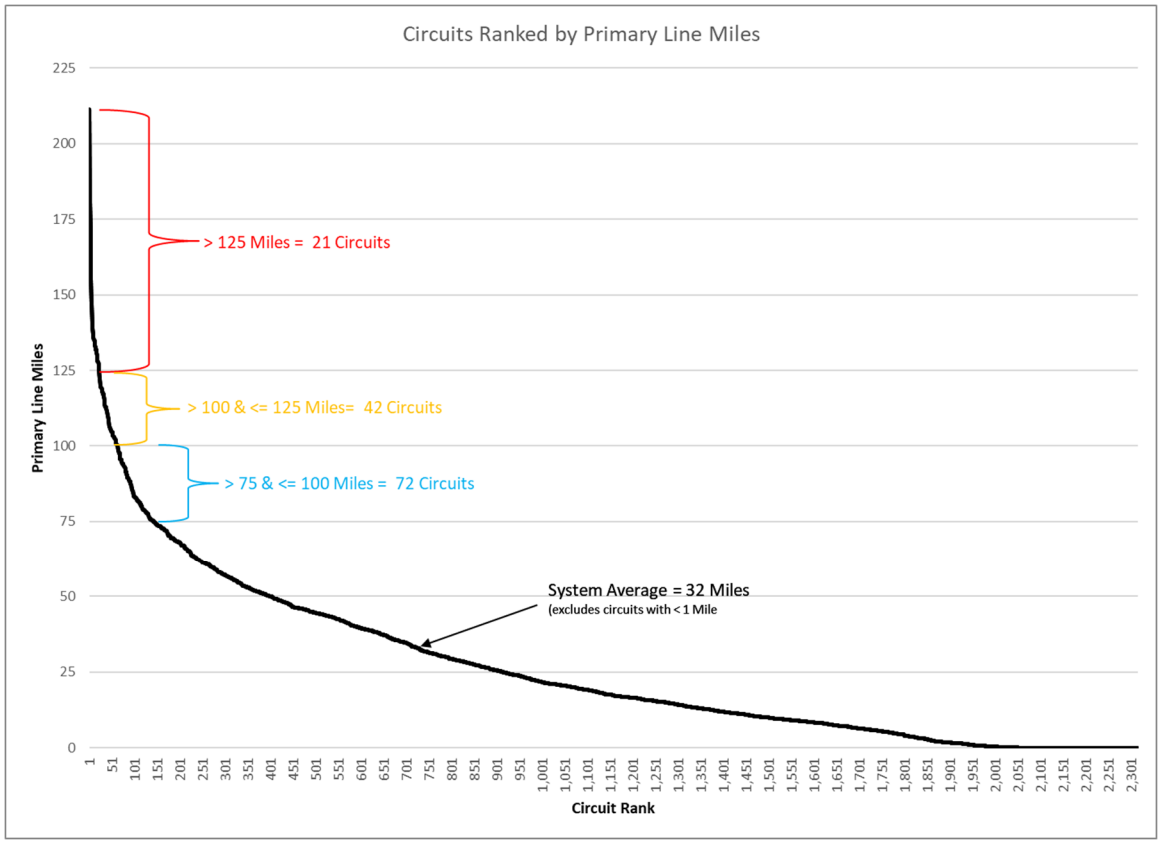
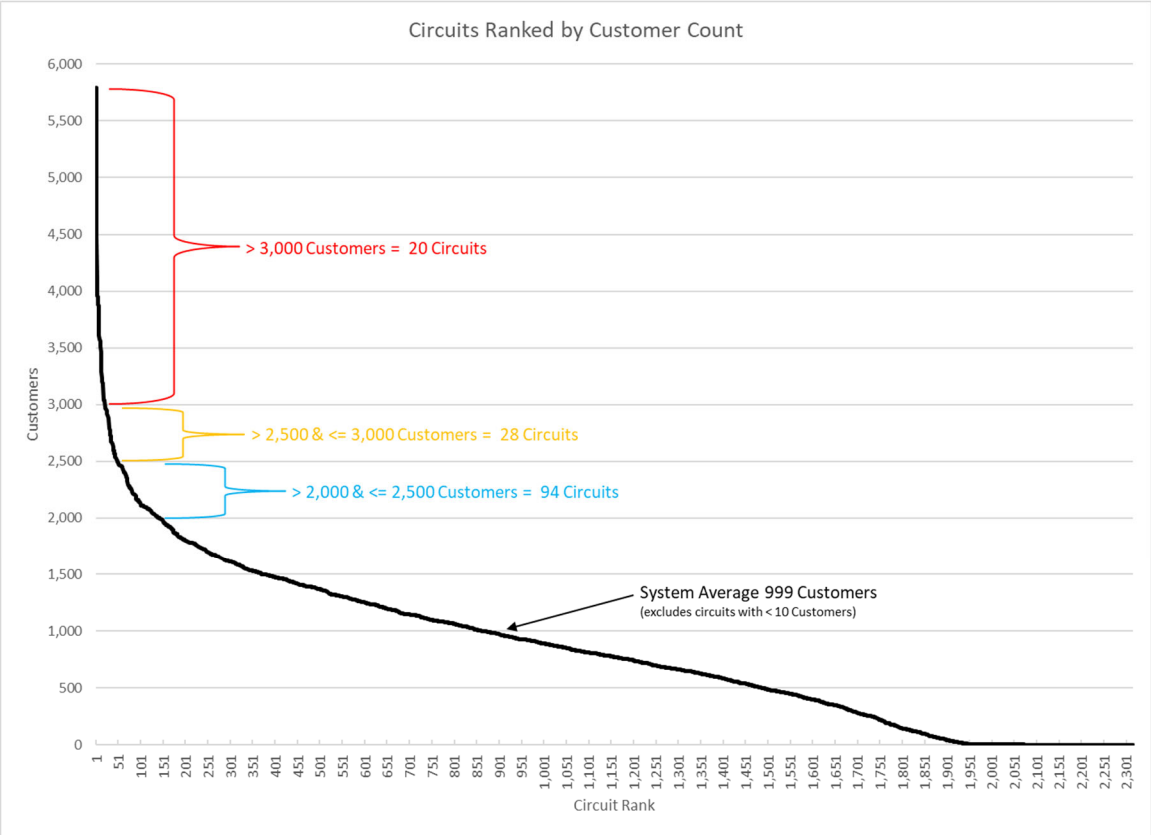


FIGURE 47
CIRCUITS RANKED BY CUSTOMER COUNT



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 will fund investments in LVD lines to completely replace certain sections of overhead LVD line with underground lines and associated equipment. This investment category will not fund undergrounding of services.

Q. Why does the Company plan to underground LVD lines?

A. During large storm events, the Company can become inundated with LVD overhead line failure incidents. 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. Targeting certain overhead lines to move underground will avoid outages on these lines caused by falling trees.

Q. What criteria was 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 will be single-phase; have had at least one outage in the last 24 months; serve between 10 and 200 customers; be operated at one of the three standard wye voltages; not be considered for another reliability project; have a load after installation of 36% or less of the ampacity of the newly installed facilities; and be 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 and weather-related outages helps to minimize future forestry clearing costs.

Q. Have any of the selection criteria changed since the Company's pilot as proposed in Case No. U-21389.

A. In the pilot in Case No. U-21389, the Company selected zones serving between 10 and 100 customers, but the upper limit has been increased to 200 customers. The pilot also focused on zones with CAIDI of over 600, and this constraint has been removed. Additionally, the pilot focused on zones with dense tree cover; as noted above, this criterion has been

redefined to focus on zones that have recently experienced significant tree and weather-related outages.

Furthermore, as discussed by Company witness Kelly, the pilot determined that undergrounding projects would have higher costs when in densely populated areas or areas that require significant boring work, and lower costs in more lightly populated areas where trenching or plowing is possible. The Company's projects in the instant case were identified based on being able to take advantage of locations that would have lower unit costs based on these lessons learned.

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-166 (JMP-1) and A-167 (JMP-2).

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 $21,194,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 20, column (k), and $35,765,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 20, column (l).

Q. Please explain how the capital expenditures projected for 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 test year for each investment category as identified in Figure 48 below.

FIGURE 48
RESILIENCY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Fractionalization	$15,826,000	8	$11,647,000	3
Overhead to Underground	$1,250,000	1.4	$20,000,000	50
EGLE - MIEJ Undergrounding Secondary and Services	$4,118,000	7	$4,118,000	9
Total	**$21,194,000**		**$35,765,000**	

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-166 (JMP-1), page 28, and for the test year, listed in Exhibit A-167 (JMP-2), page 21. Projected project costs were developed considering estimated costs for materials and labor and the Company's previous experience performing similar projects. This exhibit also identifies the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes. The Backus, Greenwood, and Mobile 27 projects, listed in Exhibit A-166 (JMP-1), page 28, lines 2 through 4, will span multiple years due to mobile substation purchase order milestone payments and construction scheduling. The Eagle and Mobile 27 projects, listed

in Exhibit A-167 (JMP-2), page 21, lines 30 and 31, will span multiple years due to mobile substation purchase order milestone payments and construction scheduling.

Q. How were the proposed Fractionalization projects identified?

A. The proposed Fractionalization projects will address four of the 40 highest customer count circuits, and four of the 40 highest line exposure circuits. Figure 49 identifies the pre-investment and post-investment configurations for these circuits benefitting more than 28,000 customers. Additional projects shown in Exhibit A-167 (JMP-2) will also address circuits with over 2,000 customers or with line exposures over 75 miles of exposure.

FIGURE 49
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
Backus Substation	Backus	Springbrook	5,587	116	Backus	Springbrook	3,564	74	217,331
	Backus	Maple Valley	1,001	60	Backus	Maple Valley	1,001	60	
					Backus	New Circuit 3	1,250	27	
					Backus	New Circuit 4	773	15	
Bennington Substation	Bennington	Manitou	759	53	Bennington	Manitou	759	53	76,750
	Bennington	Grand River	1,390	114	Bennington	Grand River	852	63	
					Bennington	New Circuit 3	538	51	
Eagle Substation	Chicago	Chicago	1892	28	Chicago	Chicago	1,892	28.077	249,309
	Chicago	Pinebrook	2650	33	Chicago	Pinebrook	1,987	25.161	
	Hager Park	Wellington	948	31	Hager Park	Wellington	553	13.885	
	Hager Park	Hager Park	3,735	58	Hager Park	Hager Park	968	31.701	
	Rosewood	Pioneer	1,171	13	Rosewood	Pioneer	1,171	12.681	
	Rosewood	Cottonwood	2,083	22	Rosewood	Cottonwood	2,083	21.844	
	Rosewood	Lamplighter	2,241	24	Rosewood	Lamplighter	1,923	20.302	
	Van Buren	Van Buren	1,871	25	Van Buren	Van Buren	1,316	17.27	
	Van Buren	Moss Lake	375	10	Van Buren	Moss Lake	375	9.58	
	Van Buren	Rush Lake	1,516	36	Van Buren	Rush Lake	680	20.943	
					Eagle	New Circuit 1	1,610	24.272	
					Eagle	New Circuit 2	1,051	16.462	
					Eagle	New Circuit 3	1,838	21.407	
					Eagle	New Circuit 4	1,035	14.923	
Greenwood Substation	Alger	Skidway	4,093	131	Alger	Skidway	613	60	361,337
	Alger	Forest Lake	1,647	117	Alger	Forest Lake	1,034	58	
	Greenwood	Rau Road	1,055	87	Greenwood	Rau Road	912	87	
	Greenwood	Indian Lake	1,240	95	Greenwood	Indian Lake	1,240	83	
					Greenwood	New Circuit 3	4,236	142	
Whittemore Substation	Whittemore	M-65	1,654	135	Whittemore	M-65	723	64	107,599
	Whittemore	Sand Lake	2,300	87	Whittemore	Sand Lake	1,907	48	
					Whittemore	New Circuit 3	457	40	
					Whittemore	New Circuit 4	867	70	

Q. Why does the projected investment level for Overhead to Underground vary between the bridge period and the test year?

A. In Case No. U-21389, the Commission approved approximately ten miles of undergrounding projects as part of a proposed pilot. In Case No. U-21585, the Company proposed to expand that pilot and continue undergrounding additional circuits, but the Commission did not approve this proposal since pilot results were not yet available. Because of this, the Company is not doing any new major undergrounding work in the bridge period in this case. The projects included in the bridge period consist of one project that was approved as part of the pilot in Case No. U-21389 that is still being finished in the bridge period ("TAWAS/TAWAS/482"). It also includes one project ("SQUIRE HILL/EDGEWATER/775") that was proposed in Case No. U-21585. The Company started work on this project at the beginning of March 2025, coincident with the test year in Case No. U-21585, before the Commission issued its final Order in that case. Because the Company had already commenced work, and because the project serves a vulnerable community, the Company will complete this work in the bridge period to deliver benefits to these customers.

As Company witness Kelly discusses, the Company now has the results of the pilot, has assessed those results, and now plans to move forward with further undergrounding work beginning in the test year. Exhibit A-167 (JMP-2), page 21, lists these new undergrounding projects.

Q. What is included in the projects in Exhibits A-166 (JMP-1) and A-167 (JMP-2) related to "undergrounding of services and secondary improvements in DACs?"

A. The Company received a grant from EGLE under Section 40101(d) of the Infrastructure Investment and Jobs Act, that is intended to underground secondary in disadvantaged communities, and these projects are where the Company will execute this work. Note that this work is separate from overhead to underground conversions, which focus on primary circuits, not on secondary.

Q. What is included in the projects in Exhibit A-167 (JMP-2), page 22, related to "Resiliency – MIEJ Hardening?"

A. These projects represent the test year work for the Company's Vulnerable Communities Resiliency Plan, as discussed in detail by Company witness Kelly.

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 the WEC Energy Group have found that undergrounding of single-phase laterals is highly effective at hardening the distribution grid from storm damage and reducing interruptions.

The picture in Figure 50 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 50
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-166 (JMP-1), page 28, and A-167 (JMP-2), page 21. Types of benefits identified on the exhibits, and summarized in Figure 51, include:

FIGURE 51
RESILIENCY BENEFITS SUMMARY

Investment Category	Benefit Categories	Bridge Period	Test Year
Fractionalization	Customer-outage-minutes avoided	1,214,132	76,750
Overhead to Underground	Customer-outage-minutes avoided	-	2,040,235
EGLE - MIEJ Undergrounding Secondary and Services	Customers	193	179

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 Kelly introduces and further discusses this program. This testimony will focus on the LVD subprograms:

(i) LVD Lines Capacity;

(ii) LVD Transformers Capacity;

(iii) LVD New Business Capacity; and

(iv) CVR.

Projected spending is explained in greater detail in the subprogram sections below. The LVD Transformers Capacity subprogram is part of a single-purchase plan, and is covered in the Meters and Transformers section of this testimony.

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[8] power engineering software to analyze loading on the distribution system. Company witness Scott A. McPhail's testimony discusses a Load Flow Tool Upgrade 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 Kelly discusses the Company's current position on NWS in his direct testimony. The Company is developing a new NWS pilot in 2025 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

[8] CYME is the trade name of the software, which was previously named Chinh Yvan Micro Engineering.

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 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?

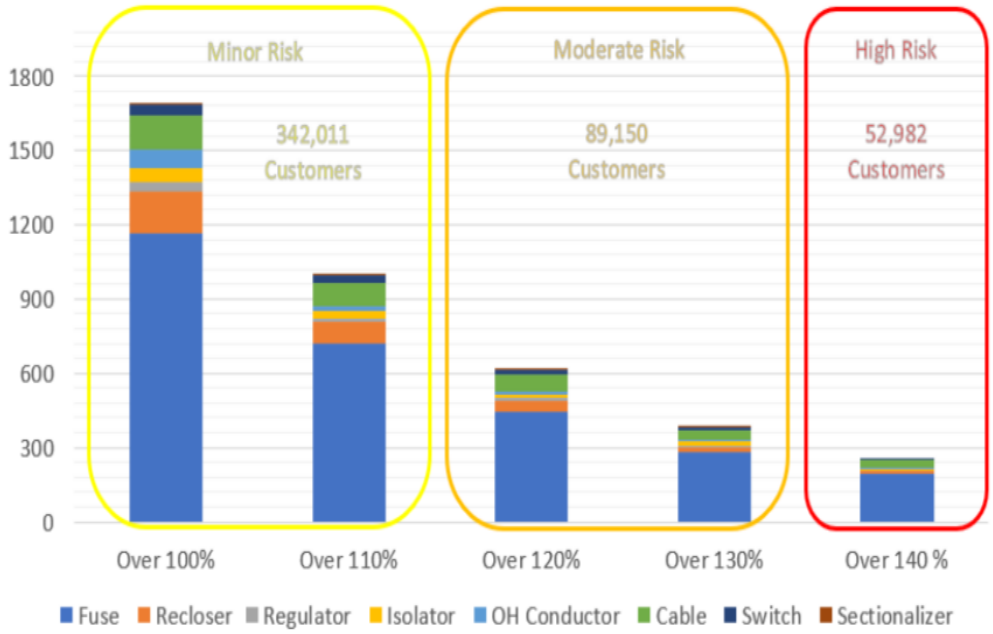
A. Substations are part of the backbone infrastructure of the electric distribution network; therefore, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation equipment reaching capacity limits. When an increase in the transformer equipment size is not a reasonable 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.

Q. How are projected LVD Lines Capacity subprogram expenditures aligned with the Reliability Roadmap?

A. The projected expenditures are directly 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 Reliability Roadmap, the Company outlined a plan to address these overload issues; while the bridge period investments in this case are aligned with levels approved by the Commission in Case No. U-21585, the test year investments represent the Company's continuation of its efforts to execute this plan at levels defined in the Reliability Roadmap. 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.

FIGURE 52
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 a situation 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, 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.

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.

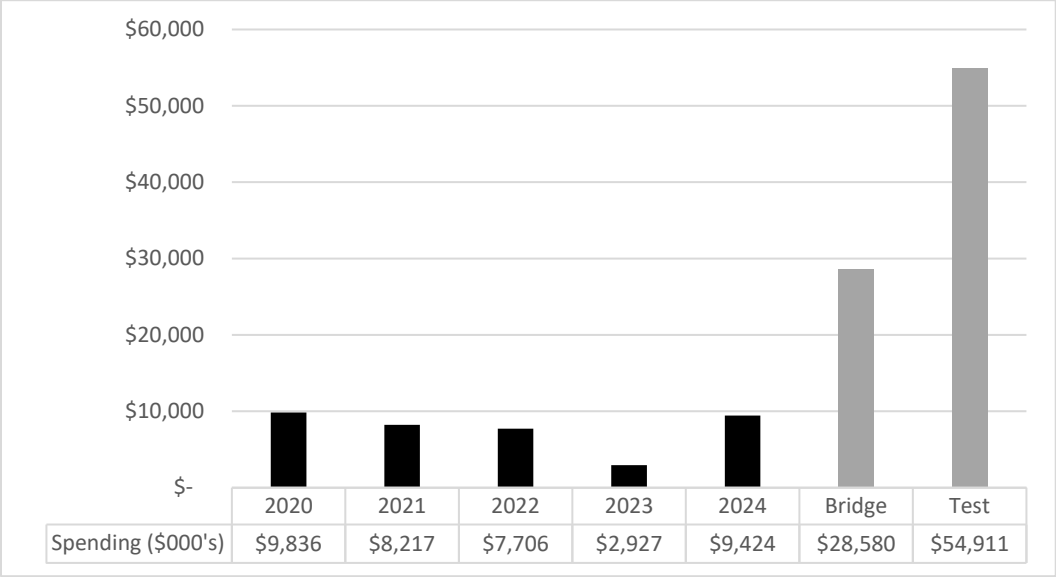
Q. Has the Company considered the impact the adoption of EVs may have on its LVD system?

A. Yes. As the Company continues to support EV growth as described by Company witness Jeffrey A. Myrom, 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 Load Flow Tool Upgrade to enhance the Company's ability to forecast and simulate the impacts of EVs and other customer technology adoption on the distribution system. This initiative is necessary to integrate EV propensity studies, 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 $28,580,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 22, column (k), and $54,911,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 22, 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-113 (MPK-3), line 22, and below in Figure 53. As discussed above, the increase in spending in the bridge period is aligned with what the Commission approved in Case No. U-21585, and the further increase in the test year is aligned with the Company's Reliability Roadmap goal of addressing all assets loaded beyond 100% of their ratings.

FIGURE 53
LVD LINES CAPACITY SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$9,836	$8,217	$7,706	$2,927	$9,424	$28,580	$54,911

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 54.

FIGURE 54
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	$21,365,000	125	$53,103,000	278
Lines capacity projects assoc. w/ substation work	$7,215,000	12	$1,808,000	3
Total	**$28,580,000**		**$54,911,000**	

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-166 (JMP-1), pages 29 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23 through 27. 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 2019, significant increases in LVD New Business, Asset Relocations, and Demand Failures work, as discussed elsewhere in my direct testimony, required the Company to shift resources away from LVD Lines Capacity to focus on work within those subprograms. A similar shift of resources was required in 2023.

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-166 (JMP-1), pages 29 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23 through 27.

Q. Does an average unit cost accurately reflect the expected spend 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 $2,000 for a protective device upgrade to $2,000,000 for a multi-mile voltage conversion project.

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.

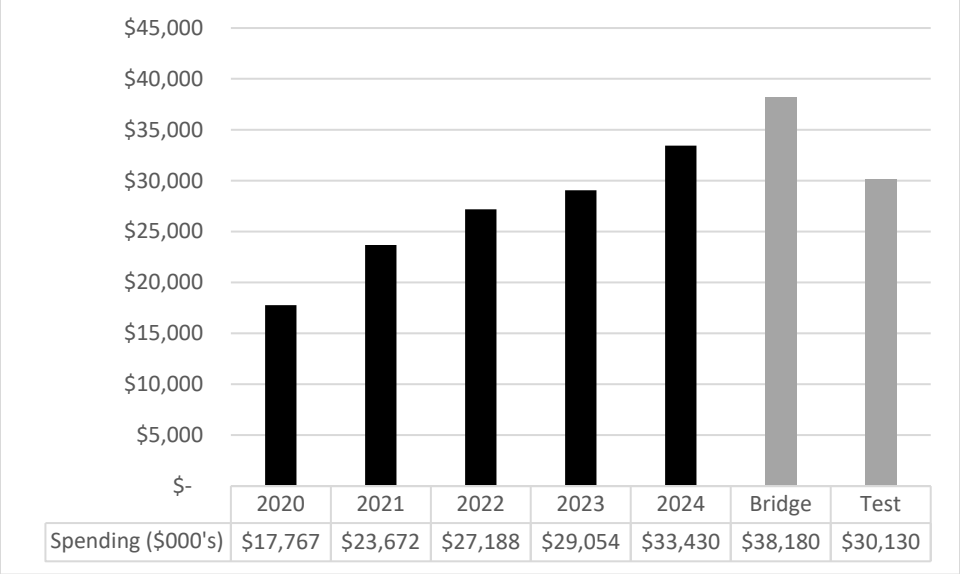
A. The Company has identified projects for the bridge period, which are listed in Exhibit A-166 (JMP-1), pages 32 through 36. Due to the nature of the New Business Capacity subprogram, only projects known in advance are listed. Accordingly, the bridge period list

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 $38,180,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 25, column (k), and $30,130,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 25, 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-113 (MPK-3), line 25, and below in Figure 55.

FIGURE 55
LVD NEW BUSINESS CAPACITY SUBPROGRAM EXPENDITURES



	2020	2021	2022	2023	2024	Bridge	Test
Spending ($000's)	$17,767	$23,672	$27,188	$29,054	$33,430	$38,180	$30,130

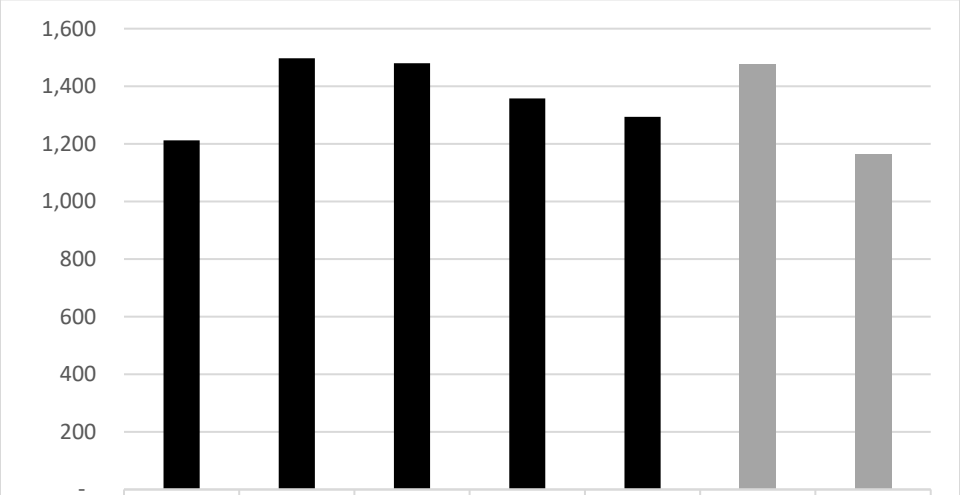
Q. How did the Company develop its projected expenditures in this subprogram?

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 2023 actual investment level and lower than the 2024 actual level (on an annual basis). The number of new business capacity orders per year increased from 1,170 in 2019 to an average of 1,377 over the last three years. Considering that fewer new business connections are expected, as described in the LVD Lines New Business section of testimony, and overloads will be reduced through the increased investment in the LVD Lines Capacity subprogram, the number of orders in this subprogram is expected to decline. However, there is not a one-to-one relationship to the LVD Lines New Business subprogram because need in the LVD New Business Capacity subprogram is driven

primarily by larger loads, such as C&I customers. The Company anticipates future per order costs for the bridge period and test year to be similar to costs experienced in 2023 and 2024. The Company projects it will complete 1,477 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 1,166 orders in this subprogram in the test year. The historical and projected number of orders is shown in Figure 56 below.

FIGURE 56
LVD NEW BUSINESS CAPACITY UNITS

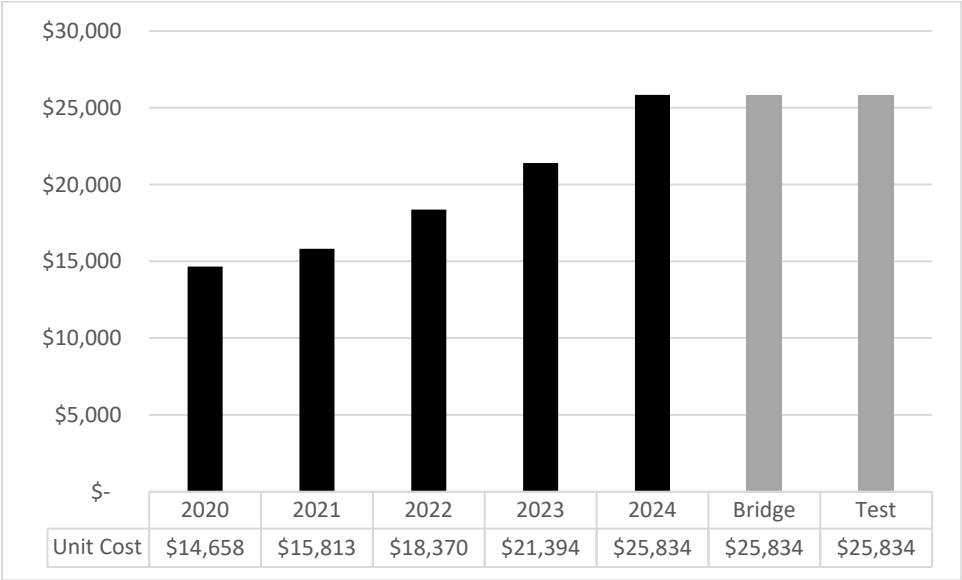


	2020	2021	2022	2023	2024	Bridge	Test
Orders	1,212	1,497	1,480	1,358	1,294	1,477	1,166

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 57 below. Unit costs in this subprogram have increased due to rising material costs such as cable and poles as discussed in the LVD Lines New Business section of my testimony.

FIGURE 57
LVD NEW BUSINESS CAPACITY HISTORICAL UNIT COSTS



	2020	2021	2022	2023	2024	Bridge	Test
Unit Cost	$14,658	$15,813	$18,370	$21,394	$25,834	$25,834	$25,834

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 58. The amount of energy savings for each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), page 37, and A-167 (JMP-2), page 28.

FIGURE 58
CVR CUMULATIVE ENERGY AND DEMAND SAVINGS

	Actual[9]					Projected[10]						
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cumulative Peak MW Reduction	0.4	5.6	14.7	21.2	~~39.1~~ 18.7	51	62	73	84	95	105	113
Cumulative MWh Reduction	82	5,643	23,882	69,045	125,746	119,379	144,102	168,971	193,976	219,160	244,450	262,399

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 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-168 (JMP-3).

[9] Actual data from Case No. U-20165, Annual Cost Reports, Exhibit 2, columns (o) and (q), Total row.
[10] Projected data from Case No. U-21090, Exhibit A-86 (MSH-1).

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 75 circuits for the bridge period, listed in Exhibit A-166 (JMP-1), page 37, and 85 circuits for the test year, listed in Exhibit A-167 (JMP-2), page 28. 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 $5,586,000 for the bridge period, as shown in Exhibit A-113 (MPK-3), line 26, column (k), and $4,070,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 26, column (l). This level of spending will enable the Company to add CVR to 85 circuits in 2025 and 85 circuits in 2026.

Q. How did the Company develop its projected expenditures in this subprogram?

A. Spending in this subprogram 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. Further, the implementation plan remains consistent with the plan presented in Case No. U-21389, with approximately 85 circuits planned per year until the final year of deployment in 2030.

Q. What has been the historical actual spending in the CVR subprogram and how does that compare to prior cases?

A. Comparisons of historical spending, projected expenditures in the case, and past approved IRP projections are shown in Figure 59. The cumulative historical expenditures plus projected expenditures in this case are compared to the cumulative approved IRP projections in Figure 59. The Company has maintained its cumulative CVR historical expenditures and rate case projected expenditures at or below the cumulative projections provided in the IRP cases.

FIGURE 59
CONSERVATION VOLTAGE REDUCTION EXPENDITURES

	Projected			Historical
	U-20165[11]	**U-21090[12]**	**This Case**	**Expenditures**
2018	$970,000			-
2019	$1,700,000			$81,743
2020	$2,500,000			$1,936,593
2021		$4,070,930		$7,191,370
2022		$4,151,389		$3,145,109
2023		$3,964,031		$1,311,828
2024		$3,877,052		$2,246,000
2025 Bridge Period		$4,391,000 --	$4,391,000 $5,586,000	
2026 Test Year			-- $4,070,000	
2020-2024 Five-Year Average	$3,712,600			$3,166,000
2018-2024 Total	$21,233,000			$15,939,643
2018-2026 Total	**$25,624,000**		**$25,595,643**	

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.

[11] Case No. U-20165, Exhibit A-67 (MAO-1), column (e).
[12] Case No. U-21090, Exhibit A-87 (MSH-2), column (f).

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 expect to maintain the network into the mid- to late- 2030s. With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations. By year-end 2025, the Company expects to have defined an approach for eventually replacing 4G meters.

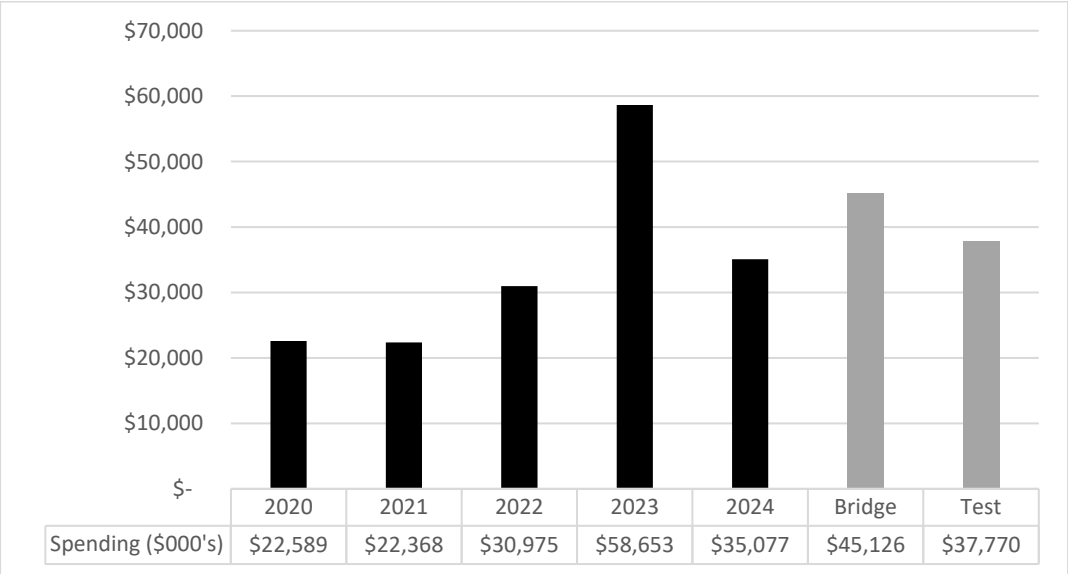
Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Metering subprograms?

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 60 below. The projections for LVD Metering capital expenditures are shown in Exhibit A-113 (MPK-3), line 35, 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 61.

FIGURE 60
METERING SUBPROGRAMS EXPENDITURES AND UNITS

Subprograms	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
LVD Metering New Business	$18,050,400	27,634	$15,108,000	20,726
LVD Metering Demand Failures	$27,075,600	41,451	$22,662,000	31,088
Total	**$45,126,000**	**69,085**	**$37,770,000**	**51,814**

FIGURE 61
LVD METERING SUBPROGRAMS TOTAL EXPENDITURES



Q. How did the Company develop its projected expenditures in the LVD Metering subprograms?

A. The expenditures in the metering subprograms 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 subprograms?

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 62 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 62 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 Company had been using and recycling inventory of these units, but the vendor discontinued the models that were being used. The new units are more expensive, and the Company is acquiring a working inventory over the bridge period and test year. 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 62
LVD METERING UNITS AND UNIT COSTS

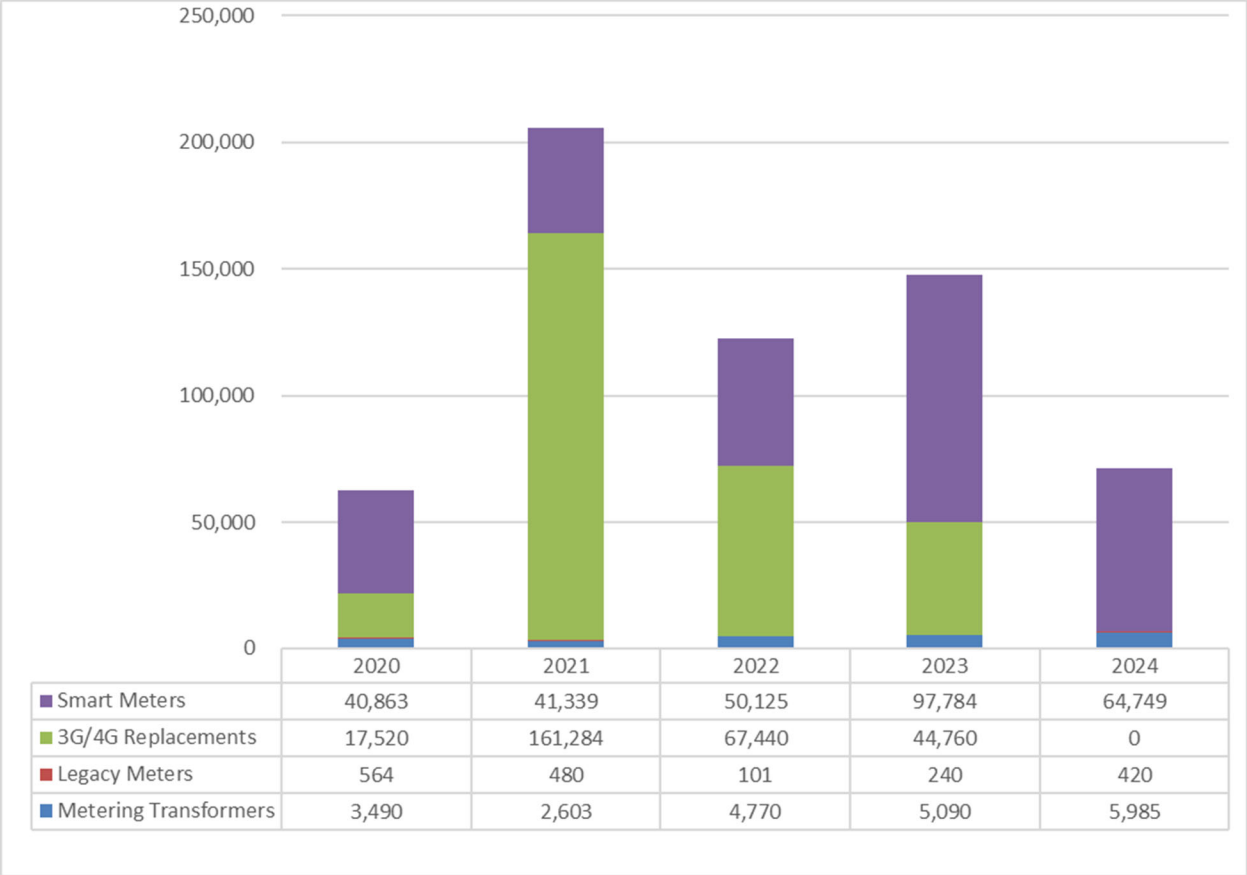
	2020	2021	2022	2023	2024	Bridge	Test
Legacy Meters							
Legacy Units	564	480	101	240	420	1,387	1,040
Unit Cost	$ 1,485	$ 105	$ 1,359	$ 149	$ 1,033	927	$ 927
Smart Meters							
Smart Meter Units	40,863	41,339	50,125	97,784	64,749	56,864	42,648
Unit Cost	$ 311	$ 293	$ 371	$ 366	$ 223	229	$ 306
3G/4G Replacements							
3G/4G Units	17,520	161,284	67,440	44,760			
Unit Cost	$ 9	$ 20	$ 18	$ 208			
Metering Transformers							
Transformer Units	3,490	2,603	4,770	5,090	5,985	10,835	8,126
Unit Cost	$ 2,026	$ 1,842	$ 1,759	$ 1,743	$ 988	$ 748	$ 761
Meter Sockets & Test Equipment							
Spending (000's)	1,821	2,244	2,642	3,763	2,974	5,213	3,910
Allocated Unit Cost Impact	$ 29	$ 11	$ 22	$ 25	$ 42	$ 75	$ 75
Total Subprogram							
Total Units	62,437	205,706	122,436	148,874	71,154	69,085	51,814
Total Unit Cost	$ 362	$ 109	$ 253	$ 390	$ 493	$ 653	$ 729

Q. Please explain the variation in total costs and in unit costs over time.

A. Total expenditures for LVD Metering have varied from year to year based on the mix in quantity and type of meters, metering transformers, and meter sockets the Company has had to purchase. During 2021, 2022, and 2023, the Company experienced increased meter failures due to contaminated meter batteries. This failure primarily occurred in meters that were outside of the manufacturer warranty period of three years. To replace the failed meters, the Company purchased additional meter quantities in 2022 and 2023 to meet the demand for failure replacements, and to complete 3G meter conversions. The unit cost for meters includes dollars allocated for meters, metering transformers, and meter sockets. 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 63.

FIGURE 63
LVD METERING UNITS



	2020	2021	2022	2023	2024
Smart Meters	40,863	41,339	50,125	97,784	64,749
3G/4G Replacements	17,520	161,284	67,440	44,760	0
Legacy Meters	564	480	101	240	420
Metering Transformers	3,490	2,603	4,770	5,090	5,985

The average unit costs in the metering transformer category were consistent from 2019 through 2023. 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 shown in Figure 64, 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 transformers purchases have been allocated across the New Business, Demand Failures, and Capacity programs for accounting reasons, but because these separate LVD transformers 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 have led to an increase in the unit costs of transformers, and while the Company is working to diversify its supply chain, it must continue to purchase transformers to meet customer demand, and in fact must increase purchase levels to catch up from shortages experienced during the COVID-19 pandemic.

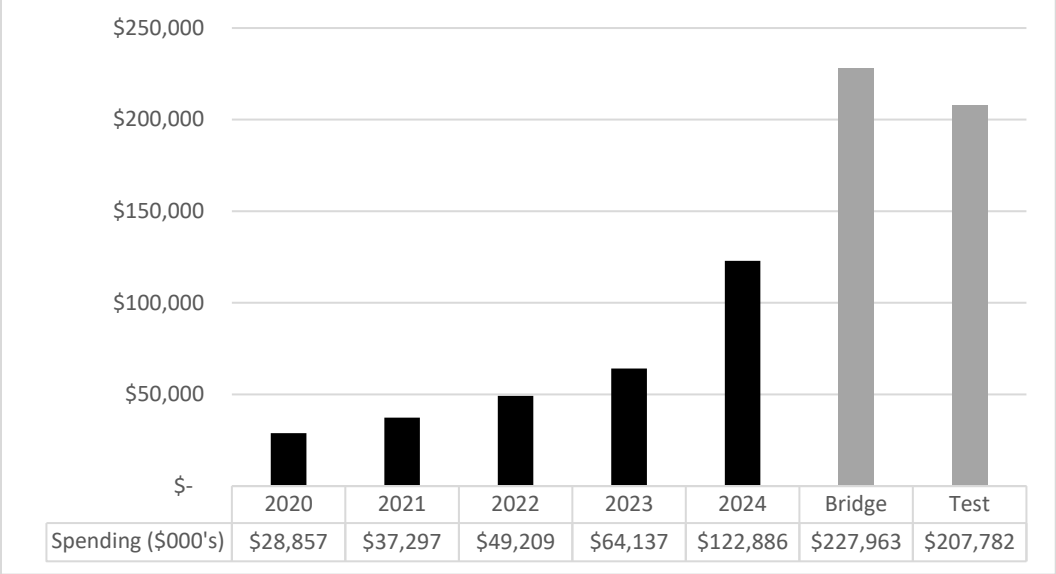
Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers subprograms?

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 $227,963,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 5, column (k), and $207,782,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 5, 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 64.

FIGURE 64
LVD TRANSFORMERS SUBPROGRAMS TOTAL EXPENDITURES

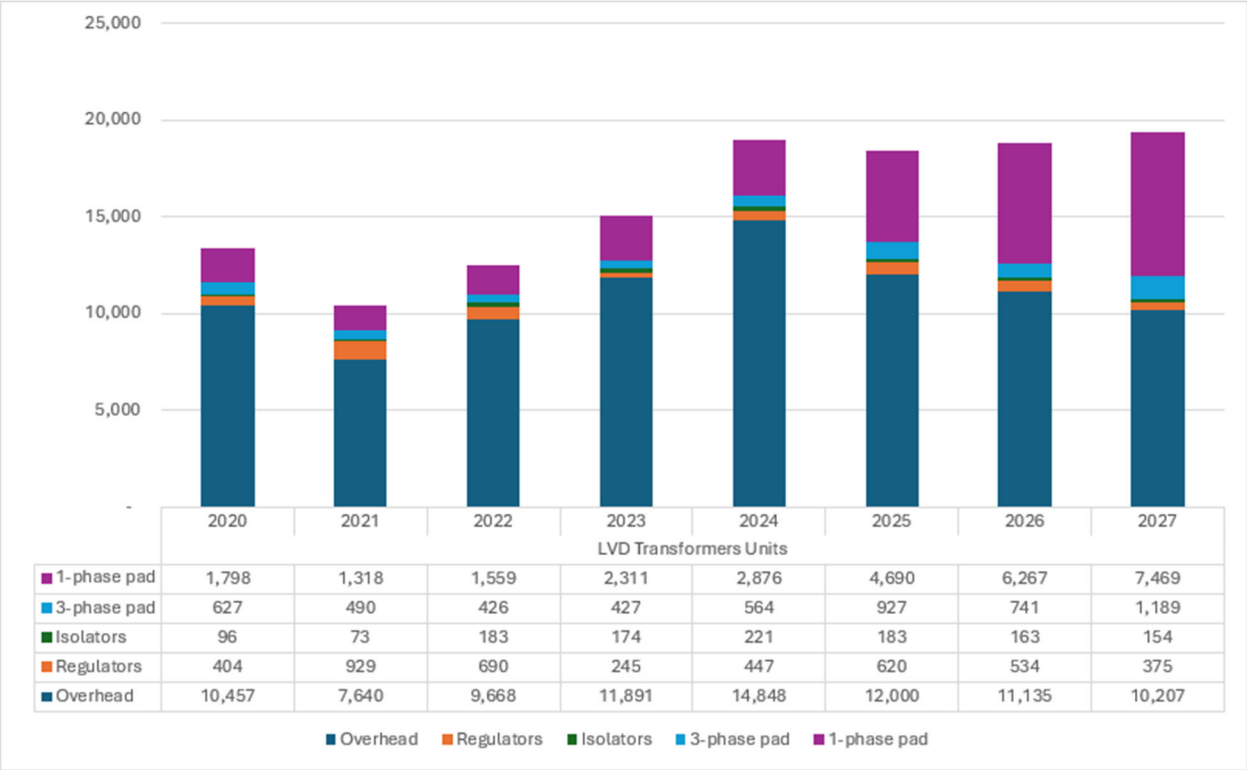


Q. How did the Company develop its projected expenditures in the LVD Transformer subprograms?

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 2024) is shown in Figure 65 below, followed by projected purchases in future years (for 2025 through 2027). In 2025 and beyond, the Company expects that purchases of overhead transformers will remain generally level, but 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 as described in the Reliability Roadmap. Furthermore, in 2022, the supply market for transformers in the United States

dropped significantly due to shortages in labor and raw materials, and the Company continues to invest in higher levels for purposes of ensuring it has restocked its inventory.

CORRECTED FIGURE 65
LVD TRANSFORMERS UNITS

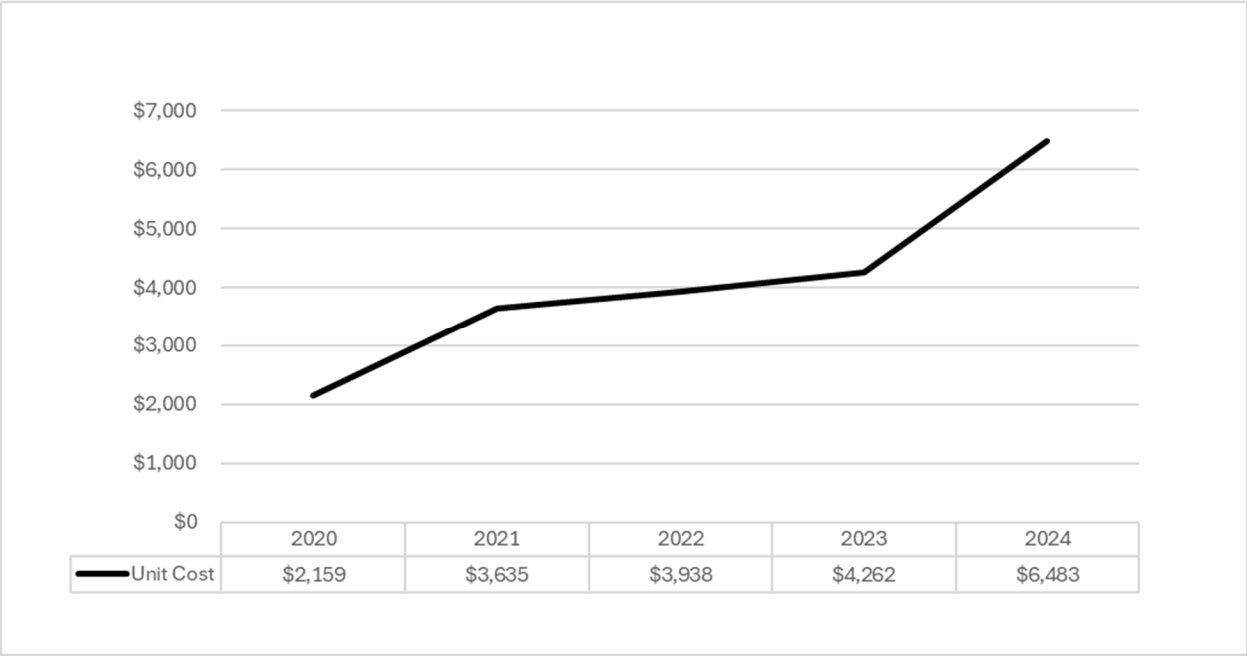


LVD Transformers Units	2020	2021	2022	2023	2024	2025	2026	2027
1-phase pad	1,798	1,318	1,559	2,311	2,876	4,690	6,267	7,469
3-phase pad	627	490	426	427	564	927	741	1,189
Isolators	96	73	183	174	221	183	163	154
Regulators	404	929	690	245	447	620	534	375
Overhead	10,457	7,640	9,668	11,891	14,848	12,000	11,135	10,207

Q. What are the historical unit costs for the LVD transformers subprogram?

A. The historical unit cost of transformers is provided in Figure 66.

FIGURE 66
LVD TRANSFORMERS UNIT COSTS



Q. Please explain any variation in unit costs over time.

A. 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. For example, in 2020 the Company received less of the more expensive units like regulators. This, coupled with increased volume of units at a lower cost, led to a lower average cost per unit in 2020. 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 as noted in this testimony. 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 addition, demand for lower-priced units like overhead transformers has slowed while demand for larger three-phase and single-phase transformers has increased in this same period. 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.

Q. Does an average unit cost accurately reflect the expected spend 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 $15,000 or more depending on application. The transformer purchase plan includes traditional transformers that serve the purpose to 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 single-phase and three-phase transformers has increased while overhead units have leveled off.

Electric Other Program

Q. What is included in the Electric Other Program?

A. Company witness Kelly introduces the Electric Other Program in his direct testimony. This testimony will address the Tools sub-program. The Electric Other Program also includes the Computers and Equipment; System Control Projects; and Grid Technologies sub-program, which are addressed by Company witness Hayward in her 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
- Sub-Station 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 $10,001,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 43, column (k), and $8,248,000 in the projected test year, as shown in Exhibit A-113 (MPK-3), line 43, 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 67 outlines the Company's bridge period investment categories and units in the Tools sub-program.

FIGURE 67
BRIDGE PERIOD INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (93 units)	$3,362,000
Other Capital Tool Purchases	
General Capital Tools	*$3,039,000*
Reconducting Trailer Equipment	*$100,000*
Employee Fall Restraint	*$250,000*
Klein Bin Storage System	*$600,000*
Substation bird mitigation equipment	*$90,000*
UG Primary Wire Stripper	*$700,000*
Digger Truck 3-Phase Holder	*$250,000*
Meter Service CT Lifters (ergonomics)	*$150,000*
Thumpers	*$100,000*
Magnetic Drills for Ductile Iron Poles	*$100,000*
Light Weight Service Savers	*$600,000*
Underground Department tools	*$660,000*
Total	**$10,001,000**

In the test year, the Company will continue with its process of purchasing truck tool kits for new Company trucks, with 62 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 the 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 68 below.

FIGURE 68
TEST YEAR TOOLS INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (62 units)	$2,015,000
Other Capital Tool Purchases	
General Capital Tools	$3,069,000
Klein Bin Storage System	$600,000
Reconductoring Trailer Equipment	$180,000
Substation bird mitigation equipment	$100,000
Battery Concrete Saw	$300,000
Underground Work Group Tool Support	$457,000
Fall Restraint	$250,000
Hydraulic Tool Replacements	$1,277,000
Total	**$8,248,000**

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 69 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 69
TRUCK TOOL PACKAGES BY YEAR

	2020	2021	2022	2023	2024	Bridge Period	Test Year
Number of truck tool packages	47	18	0	16	24	93	62
Truck tool package spending	$2,736,000	$5,885,000	$0	$560,000	$727,000	$3,362,000	$2,015,000

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 70 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 70
TOOLS HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
$3,611,000	$5,214,000	$5,257,000	$4,560,000	$7,773,000	$5,283,000

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 Kelly.

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 71 below. Dollars shown are in thousands.

FIGURE 71
LVD CAPITAL EXPENDITURE SUMMARY ($000)

	2024 Actuals	Bridge Period	Test Year
LVD Capital	$632,197	$1,055,533	$1,086,679

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-21870

REVISED EXHIBIT

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Revised Exhibit No.: A-169 (JMP-4)
Page: 1 of 4
Witness: JMPartlan
Date: June 2025

Line		2023	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT COTTAGE GROVE PREVO LCP 259	4,209	2	5	0	1	0
2	RPOUT17 PINCONNING_PINCONNING LCP 693	12,590	0	0	0	1	0
3	RLBY ASHMAN-ASHMAN, LCP 765	71,373	1	0	0	0	0
4	RPOUT BUSCH ROAD/CANADA LCP 734	7,463	1	4	1	0	0
5	RPOUT ST CHARLES_SAGINAW LCP 652	134	0	1	0	1	0
6	RPOUT APPLETON-PERRY LCP 957 OVERLOAD	11,240	0	0	0	1	0
7	RPOUT Remus-Mecosta* LCP 126 Overload	37,518	0	0	0	0	0
8	RPOUT Ensley-Distribution LCP 707	26,845	2	2	0	1	0
9	RPOUT Ohman Road-Sears LCP 736*	59,669	6	0	1	0	0
10	RPOUT Ohman Road-Sears* LCP 002	116,708	6	2	2	1	0
11	RPOUT Rodney-Rodney LCP 310 - OHL	9,312	3	1	0	0	0
12	RPOUT Rodney-Horsehead Lake LCP 241*	15,445	2	2	1	1	0
13	RPOUT Rodney-Rodney LCP 310 - UGL	5,564	3	1	0	0	0
14	RPOUT Foreman Vergennes LCP 572	80,560	3	1	2	0	0
15	RPOUT CALEDONIA-92ND STREET email	22,854	0	0	0	0	0
16	RPOUT Alto McCords 60th St SE	7,738	1	0	2	1	0
17	RPOUT DUTTON DUTTON LCP 228	105,115	0	0	0	0	0
18	RPOUT Calvin Woodcliff LCP 144-ZLD HDQ	65,531	0	1	0	0	0
19	RPOUT Orleans Orleans 091 PREBUILT	1,738	3	1	0	2	0
20	RPOUT HARVARD LAKE/HARVARD LAKE SUB #1	72,196	4	2	0	0	0
21	RPOUT HARVARD LAKE/HARVARD LAKE SUB #2	64,582	4	2	0	0	0
22	RPOUT CARSON CITY/HARVEST LCP 420*	16,158	3	2	0	0	0
23	RPOUT Godfrey LCP 545	10,295	3	1	2	0	0
24	RPOUT Hubbardston LCP 325	23,997	3	1	0	1	1
25	RPOUT ORLEANS LONG LAKE LCP 147	21,457	4	1	0	0	1
26	RPOUT ORLEANS LONG LAKE LCP 169	14,897	5	1	1	0	1
27	RPOUT Orleans_Long Lake LCP 030 OL	12,196	0	0	0	0	0
28	RPOUT CARSON CITY_BUTTERNUT LCP 0002*	25,087	0	6	0	0	0
29	RPOUT CRYSTAL_CRYSTAL ROAD LCP 554	31,078	5	1	0	0	0
30	RPOUT KENT CITY/TYRONE LCP-510	3,210	0	0	0	0	0
31	RPOUT KENT CITY_CASNOVIA LCP-869	18,673	4	0	0	2	0
32	RPOUT PLAINFIELD/KUTTSHILL* LCP-051	98,904	0	0	1	1	0
33	RPOUT COWAN LAKE_RAMSDELL* LCP-657	15,823	0	0	1	0	1
34	RPOUT Cedar Springs-Edgerton LCP 705	18,191	3	1	0	0	0
35	RPOUT Kent City_Casnovia* First Zone Fus	9,226	3	4	6	4	1
36	RPOUT Pierson-Pierson* LCP 605	3,617	3	1	1	0	0
37	RPOUT RATIGAN_GREELEY* LCP-002	17,616	0	1	1	0	0
38	RPOUT LINDEN N LINDEN LCP 720	588	0	0	0	1	0
39	RPOUT Clio/Pine Run LCP 771	2,083	0	0	1	0	0
40	RPOUT Mayfair/Home TLM 0856264411 CPLT	82,752	4	2	0	0	0
41	RPOUT Mayfair/Home TLM Edwards Ave	159	4	2	0	0	0
42	RPOUT Mayfair/Home Edwards Ave	114	4	2	0	0	0
43	RPOUT Mayfair/Home TLM Dupont St	171	4	2	0	0	0
44	RPOUT MT MORRIS/NEFF TLM 0856121103 CPLT	73,277	4	1	0	0	0
45	RPOUT Otisville/Irish Rd LCP 59	4,445	2	0	1	0	1
46	RPOUT MAYFAIR HOME TLM 0856264404	39,442	4	1	1	0	0
47	RPOUT STANLEY NORTHLAND TLM 0856241204	31,002	2	1	1	0	0
48	RPOUT Field Rd/Parker Crk TLM0956191101	22,590	4	0	1	0	0
49	RPOUT Mayfair/Home TLM 0856264404 5605 B	130	4	1	1	0	0
50	RPOUT Mayfair/Home TLM 0856264404 5518 G	153	4	1	1	0	0
51	RPOUT MAYFAIR/MAYFAIR TLM 0856342103	98,075	3	1	0	0	1
52	RPOUT MAYFAIR/MAYFAIR - OHS 3509 MINERVA	154	3	1	0	0	1
53	RPOUT MAYFAIR/MAYFAIR- OHS 3302 WINDLAND	170	3	1	0	0	1
54	RPOUT IRISH ROAD_CRYSTALWOOD LCP 196	2,032	0	3	0	0	0
55	RPOUT SPRING DRIVE FERRIS - LCP 380	23,809	0	1	1	0	0
56	RPOUT_Manistee_Lake Michigan	7,440	1	0	0	0	1
57	RPOUT ORIOLE HAMLIN LCP 0728 - OHL	27,703	2	1	2	1	0
58	RPOUT ORIOLE HAMLIN LCP 0728 - UGL	127,004	2	1	2	1	0
59	RPOUT AGNEW ROBINSON	12,064	0	0	0	0	0
60	RPOUT NORGE MACHINE EDGEWATER RECL	121,252	2	1	0	1	0
61	RPOUT NUNICA_WILSON SUB	13,699	3	2	3	2	0

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Revised Exhibit No.: A-169 (JMP-4)
Page: 2 of 4
Witness: JMPartlan
Date: June 2025

		2023	Outage Data				
Line	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
No.	RPOUT EVANSTON EVANSTON LCP 564	4,970	1	1	0	0	0
1	RPOUT18 GLADWIN/GLADWIN LCP825 LOC 13-28	15,313	2	0	0	1	4
2	RPOUT18 GLADWIN/GLADWIN LCP 825 LOC 1-12	128,202	2	0	0	1	4
3	RPOUT22 OBERLIN BENMARK LCP 604	9,406	0	4	0	0	0
4	RPOUT22 GLADWIN BUZZELL LCP 310 CMPLT	8,904	5	0	0	0	0
5	RPOUT LCP 866 SMALLWOOD DIST	41,803	3	0	0	1	0
6	RPOUT22 BEAVERTON ROSS ST LCP 504 COMPLT	8,056	3	0	0	0	0
7	RPOUT NOBLE_DUBY LCP 7299	45,857	5	0	0	0	0
8	RPOUT BACKUS-SPRINGBROOK COORD	20,318	2	1	1	1	1
9	RPOUT Duquite_Saganing LCP 960	9,841	0	0	0	0	0
10	SYSP BESSINGER_QUARRY LCP 423 - 2 crews	29,721	0	0	0	0	0
11	RPout Pellston_Burtlake LCP 283	25,126	9	1	0	1	1
12	RPOUT LAKE CITY-STITTSVILLE COORD	5,458	0	0	0	1	0
13	RPOUT Hospital/Kids Creek LCP 740	79,626	5	2	0	0	0
14	RPOUT Hospital/Kids Creek LCP 740 UGL	97,229	5	2	0	0	0
15	ON HOLD -- RPOUT Bedford - Meachem LCP 7	1,715	4	0	0	3	0
16	RPOUT Alder Creek - E Leroy LCP 529	2,945	5	0	1	2	0
17	RPOUT Elm St-Verona LCP 281 (SECTRPL)*CE	142,293	1	1	0	1	0
18	RPOUT Elm St-Verona LCP 353(SECTRPL)*CE	40,021	1	0	0	0	0
19	RPOUT - Convis Convis various lcps	7,875	1	1	2	1	0
20	*RPOUT - 15 Mile A Drive 773*CE CREWS	6,462	0	0	0	0	0
21	RPOUT Athens - Sherwood	86,925	1	1	3	1	0
22	RPOUT DELTON_DELTON LCP 087	36,467	1	5	2	1	0
23	RPOUT22 RIX ROAD_UNDERPASS	15,356	2	0	1	2	0
24	RPOUT ATWATER-CRONK	11,295	3	0	1	0	0
25	RPOUT GLENDALE_HERCULES	16,520	2	0	2	1	0
26	RPOUT PICKEREL_EAST LAKE LCP 223	39,550	4	0	0	2	0
27	RPOUT17 PORTAGE/CARPENTERS CORNERS	26,586	2	0	1	1	0
28	RPOUT ALAMO-PINE GROVE LCP 638	41,314	0	4	2	3	1
29	RPOUT ALAMO_PINE GROVE LCP 5193	71,883	0	7	3	1	0
30	RPOUT GALESBURG_CHARLESTON LCP 574 *401	81,603	0	5	0	1	1
31	RPOUT PICKEREL_EAST LAKE LCP 223 - UG	21,023	4	0	0	2	0
32	RPOUT 25 1_2 Mile Rd	859	1	0	1	2	0
33	RPOUT READING_CAMBRIA	11,493	1	2	3	0	0
34	B2LN5021 RPOUT21 CENTREVILLE_BUSINESS LC	2,311	1	2	5	0	0
35	CEMI11 CARLETON ROAD_BECK ROAD	172,546	4	0	1	0	0
36	RPOUT-DOBSON RD HALF MOON 354	3,356	0	0	0	0	0
37	RPOUT21 CENTREVILLE_INDUSTRIAL LCP 502	90,314	2	0	2	0	0
38	RPOUT READING_CAMBRIA LCP 649	12,392	1	3	1	2	0
39	LNDC RPOUT CEMI12 QUINCY_QUINCY OHL	1,000	2	1	1	0	0
40	RPOUT CEMI12 QUINCY_QUINCY LCP 769	40,388	2	1	1	0	0
41	RPOUT CEMI12 QUINCY_QUINCY LCP 769 UGL	11,813	2	1	1	0	0
42	RPOUT Breton Towers LCP 687 ZLD HQ	50,491	0	0	1	0	0
43	RPOUT22 Ramona/Robinson New Recloser	75,235	1	1	0	1	0
44	RPOUT FILLMORE-N BLENDON 602	13,677	3	0	3	1	0
45	RPOUT Breton Towers Sub	32,777	6	0	1	1	0
46	RPOUT FILLMORE_64TH STREET LCP SUB	11,998	3	1	0	0	0
47	SYSP OTTAWA BEACH-LAKEWOOD	946	0	1	0	10	0
48	RPOUT LCP 538 OTTAWA BEACH-LAKEWOOD OHL	5,249	3	3	1	0	0
49	RPOUT CASCO_BLUFF LCPS SUB 385 394 226 (	7,899	2	1	1	1	0
50	RPOUT MACATAWA WENDT PARK LCP 617 *carde	42,551	1	0	1	0	0
51	RPOUT BENTHEIM_140TH AVENUE LCP 306 OHL	153,891	5	3	0	0	0
52	RPOUT BLACK RIVER FILLMORE LCP 459	1,955	0	0	0	0	0
53	RPOUT BELKNAP-TODD FARM SYSP2021	1,157	1	1	0	0	0
54	RPOUT VIRGINIA PARK_CASTLE BEELINE RD *s	36,375	2	0	0	0	0
55	RPOUT MILL GROVE_ALLEGAN HYDRO LCP 378	1,362	4	6	5	1	0
56	RPOUT MILL GROVE_ALLEGAN HYD	101,845	4	6	5	1	0
57	RPOUT MERSON DUCK LAKE LCP 961	49,082	3	1	5	2	0
58	RPOUT LCP 538 OTTAWA BEACH-LAKEWOOD UGL	74,710	3	3	1	0	0
59							

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Revised Exhibit No.: A-169 (JMP-4)
Page: 3 of 4
Witness: JMPartlan
Date: June 2025

Line		2024	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT17 ITHACA/FAIR GROUNDS LCP 313	47,942	2	1	3	3	0
2	RPOUT17 ITHACA/FAIR GROUNDS LCP 331	25,717	0	0	0	1	0
3	RPOUT COTTAGE GROVE PREVO LCP 259	10,077	2	5	0	1	0
4	RPOUT COGGINS_NEWBERG LCP 082	26,530	0	4	0	0	0
5	SYSP COTTAGE GROVE PREVO LCP 866	53,439	6	1	0	2	0
6	SYSP MT FOREST BENTLEY 746 REACH	30,125	2	2	1	5	0
7	SYSP KAWKAWLIN RUSSELL 786	24,578	4	1	1	3	0
8	RPOUT LETTS ROAD_MONROE LCP 212	3,593	7	1	2	7	0
9	SYSP19 Bradford_Distribution LCP 057	6,880	1	1	0	2	0
10	SYSP19 Waldo Jefferson SUB	35,270	0	0	1	1	0
11	SYSP19 Price Road_Price LCP 424	14,571	1	0	0	2	0
12	SYSP19 Letts Road_Walker LCP 771	27,150	5	2	0	2	0
13	RPOUT ST CHARLES_SAGINAW LCP 652	6,551	0	1	0	1	0
14	RPOUT BELL ROAD/ALBEE LCP 922	15,196	0	1	3	1	1
15	RPOUT24 Hemlock Nelson LCP585	38,268	2	3	1	1	0
16	RPOUT OHMAN ROAD_SEARS LCP 809	15,968	0	4	0	0	1
17	RPOUT TAMARACK_AMBLE LCP 521	19,236	0	2	0	0	0
18	RPOUT_ENSLEY_BAPTIST LAKE_LCP 754	351	0	0	0	0	0
19	RPOUT CONKLIN PARK_HOLLY LCP 857	4,945	1	0	4	0	0
20	RPOUT Broadmoor Airwest LCP 544 OHL	16,080	0	0	0	0	0
21	RPOUT Thornapple Headley LCP 435	41,588	1	4	3	0	0
22	RPOUT FULTON_RIPPLING LCP 740	15,350	0	1	0	0	0
23	RPOUT KENTWOOD_PRINCETON LCP 0639	56,916	1	0	2	1	1
24	RPOUT BROADMOOR_MEADOWLANE LCP 0262	76,949	0	0	0	0	0
25	RPOUT22 Godfrey_Lowell	68,415	0	0	0	1	0
26	RPOUT Easton_Haynor LCP 380	17,427	3	2	2	3	1
27	RPOUT EASTON_PARMETER LCP 844	127,246	4	1	2	0	0
28	RPOUT Saranac_Centerline LCP 196**	16,487	0	0	1	2	0
29	RPOUT PECK ROAD_M-91 LCP 428	7,904	0	0	0	0	1
30	RPOUT PEACH RIDGE/BALLARD SUB REACH ISSU	3,475	0	0	0	0	0
31	RPOUT** Bella Vista_Bella Vista LCP495-5	4,460	0	0	0	1	0
32	RPOUT Pierson-Whitefish LCP 603	21,107	3	2	0	2	0
33	RPOUT Hull St_Cranberry LCP-021 Fuses**	7,716	2	2	0	1	0
34	RPOUT ROCKFORD_SUMMIT LCP 565	3,774	3	0	1	1	1
35	RPOUT NORTH PARK_COIT LCP-474**	626	0	0	0	0	0
36	RPOUT LINDEN N LINDEN LCP 720	13,958	0	0	0	1	0
37	RPOUT RANKIN_TRAPANI LCP 337	42,995	3	1	0	0	0
38	RPOUT Kearsley/Shillelagh LCP 599	115,569	3	1	0	1	0
39	RPOUT StanleyNorthland Sub Reach	11,942	1	2	0	2	0
40	RPOUT SLOAN LAVELLE LCP 319	9,794	1	0	1	0	0
41	RPOUT Mayfair Cass LCP 832	8,227	2	1	0	1	0
42	RPOUT Clio/Pine Run LCP 771	59,061	0	0	1	0	0
43	RPOUT STANLEY NORTHLAND TLM 0856241204	409	4	1	1	0	0
44	RPOUT Kearsley/Craig TLM 0857342305	51,690	4	0	0	1	0
45	RPOUT IRISH ROAD_CRYSTALWOOD LCP 196	67,201	0	3	0	0	0
46	SYSP WEST FENTON NORTH ROAD LCP#702	166,667	1	5	0	0	0
47	RPOUT Otisville/Irish Rd LCP 591	45,621	2	0	1	0	1
48	RPOUT RUSSELLVILLE/RICHFIELD LCP 435	107,638	0	1	0	0	0
49	SYSP WEST FENTON OVERPASS LCP#329	35,833	0	0	0	0	0
50	RPOUT BEERS-SHARP LCP 281	9,242	0	0	0	3	0
51	RPOUT - GRANT-GRANT - LCP 355	14,936	3	1	1	2	1
52	RPOUT - GRANT-CATALPA - LCP 380	66,685	5	1	2	0	0
53	RPOUT HESPERIA_RURAL LCP 938	11,491	1	0	0	8	0
54	RPOUT Washington_Madison LCP 423	3,958	0	0	0	0	0
55	RPOUT BALDWIN IDLEWILD LCP 267	4,959	1	0	0	0	0
56	RPOUT WASHINGTON_CONRAD LCP 429	1,879	0	0	0	0	0
57	RPOUT SCOTTVILLE US31 LCP 397	7,131	1	2	4	1	0
58	RPOUT ORIOLE_WHITTIER LCP 385	1,861	0	0	0	0	0
59	RPOUT MANISTEE_LAKE MICHIGAN LCP 070	3,088	1	0	0	0	0
60	RPOUT BALDWIN_IDLEWILD LCP 463	3,457	0	0	0	0	0
61	RPOUT AGNEW ROBINSON	18,354	0	0	0	0	0
62	RPOUT HAYES STREET BUCCANEER	18,675	1	0	2	1	0
63	RPOUT NESTROM_SOUTH SHORE LCP 546	224,779	2	5	2	5	0

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Revised Exhibit No.: A-169 (JMP-4)
Page: 4 of 4
Witness: JMPartlan
Date: June 2025

Line		2024	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT TWIN LAKE_TWIN LAKE LCP 604	5,339	0	0	3	1	0
2	RPOUT WHITEHALL_ALICE LCP 874	7,848	1	1	3	4	0
3	RPOUT TERRACE_MALL LCP 362	9,559	0	0	0	0	0
4	RPOUT HYDE PARK_DUCK LAKE LCP 279	2,242	0	0	0	1	0
5	RPOUT ROTHBURY_FERRY LCP 457	2,102	0	0	0	0	0
6	RPOUT SHELBY_PINE STREET LCP 704	2,263	0	0	0	0	0
7	RPOUT GETTY MARQUETTE LCP 848	3,740	1	0	0	0	0
8	RPOUT BENSTON_LEWIS LCP 0633	1,619	0	0	0	1	0
9	RPOUT TWIN LAKE_RILEY THOMPSON LCP 344	2,207	2	1	0	4	0
10	RPOUT TWIN LAKE_RILEY THOMPSON LCP 247	16,228	1	0	2	3	0
11	RPOUT NESTROM_SOUTH SHORE	3,677	2	5	2	5	0
12	RPOUT NORTH MUSKEGON_DALTON LCP 279	3,949	0	0	1	4	0
13	RPOUT TWIN LAKE_TWIN LAKE LCP 568	1,706	3	2	0	6	0
14	RPOUT DUPONT_OLD CHANNEL LCP 415	22,878	2	0	0	0	0
15	SYSP18 SMALLWOOD DAM WOODEN SHOE LCP 930	3,903	0	0	1	0	0
16	RLBY20 SURREY SURREY LCP 188	49,473	5	1	1	1	0
17	SYSP20 EIGHT POINT WHT BIRCH LCP 298	3,780	0	0	0	0	0
18	SYSP18 FROST LONG LAKE LCP 535	1,262	0	0	0	0	0
19	SYSP18 SURREY SURREY LCP 699	439	0	1	0	0	0
20	RPOUT24 HARRISON HARRISON LCP 5926	10,336	1	2	1	6	1
21	SYSP ALCONA DAM_CURTISVILLE	1,075	1	0	0	2	0
22	SYSP EAST TAWAS_LINCOLN STREET	11,658	2	0	1	2	0
23	RPOUT BACKUS-SPRINGBROOK COORD	65,225	0	0	0	0	0
24	RPOUT18 ONEKAMA-CHIEF LCP 608	189	0	1	0	1	1
25	RPOUT Frankfort-Crystallia LCP 397	15,228	2	0	0	0	0
26	RPOUT ARCADIA-PLEASANTON LCP 8567	739	0	0	0	0	0
27	RPOUT ARCADIA-STARKE MULT LCP	6,380	0	0	0	0	0
28	RPOUT HIGH BRIDGE-KALEVA LCP 874	7,764	0	1	1	0	0
29	RPOUT HONOR_PLATTE LCP 0594	4,028	1	3	3	1	1
30	RPOUT HIGH BRIDGE-CREAMERY LCP 900	2,489	0	0	0	0	0
31	RPOUT PELLSTON_BURT LAKE LCP 516	2,800	0	3	2	0	2
32	RPOUT WOODWARD-WOODWARD LK 23 RD	7,179	2	1	0	2	0
33	RPOUT ZONAL FUSE INSTALL 0380_02	29,414	4	1	3	1	1
34	RPOUT 22 BROUGHWELL MINARD LCP	225,750	2	0	0	0	0
35	RPOUT24 BATTEESE_PLEASANT LAKE	10,077	0	0	2	0	0
36	ATR22W UG CLARK LK-EAGLE-DARE 13 HAYES	790	0	0	0	1	0
37	SYSP Bath-Park Lake	63,486	0	0	0	1	0
38	RPOUT BATH SUB - BATH CKT LCP 215	88,786	2	5	1	1	0
39	VOLT WHITTUM KINNEVILLE INSTALL RE-REG	9,314	0	0	0	0	0
40	SYSP MASON SOUTH ST. FUSE COORDINATION	9,953	0	0	1	0	2
41	Dare Perry Perry Rep LCP 595/140A reclos	16,189	0	0	0	0	0
42	RLBY LAINGSBURG_LELAND ROAD LCP 447	4,719	0	0	1	1	0
43	RPOut Athens - Athens LCP 494	2,329	1	1	0	0	0
44	RPOUT14 Pennfield/Pennfield LCP504 #1	930	1	1	0	0	0
45	RPOUT Alder Creek - Lee Lake LCP 221	14,343	3	5	2	0	0
46	RPOUT HASTINGS HANOVER LCP 630	89,886	3	0	0	1	0
47	FUSE24 HASTINGS_BOLTWOOD - ESIC OHL	13,730	0	0	0	0	0
48	RPOUT RIX ROAD_UNDERPASS LCP 637	245	2	3	1	7	0
49	RPOUT SCOTTS-SCOTTS	468	1	0	0	1	0
50	RPOUT RICHLAND-D AVE	2,221	0	0	0	1	0
51	RPOUT LAWRENCE_BRUSH CREEK ESIC OHL	40,978	0	0	0	0	0
52	RPOUT22 ALAMO_FISH HATCHERY 209	52,015	1	3	1	1	0
53	RPOUT PICKEREL_EAST LAKE LCP 278 *317	83,635	3	0	0	2	0
54	RPOUT ALAMO-PINE GROVE_LCP 844 *412	62,583	3	5	1	4	0
55	RPOUT KILGORE WISTERIA	71,574	1	0	2	0	0
56	RPOUT MILLERS POINT_HOLIDAY LCP SUB	22,144	1	0	1	0	0
57	RPOUT UGL KILGORE MILHAM-TRADE CENTER WA	704,049	0	0	3	2	0
58	604 GOLDEN DR, KZO -	73,856	0	2	0	0	0
59	RPOUT HOMER_INDUSTRIAL LCP 685	3,121	1	1	0	0	0
60	RPOUT DOBSON ROAD_HALF MOON LCP 275	8,073	5	1	8	0	0
61	RPOUT LITCHFIELD_QUAKER LAKE PH SWAPS	24,858	0	0	0	0	0
62	RPOUT - Reading City Various fusing	14,524	1	0	1	0	0
63	LNDC RPOUT CEMI12 QUINCY_QUINCY OHL	1,000	2	1	0	1	0
64	RPOUT CEMI12 QUINCY_QUINCY OHL PART 2 *4	38,296	2	1	0	1	0
65	FAIL24READING-CAMBRIA-7510 READING RD-RE	26,599	1	2	3	0	0
66	RPOUT CEMI12 QUINCY_QUINCY OHL *DAYBURG.	134,487	2	1	0	1	0
67	RPOUT CARLETON RD_GAIGE RD	16,073	0	0	0	0	0
68	RPOUT CEMI12 QUINCY_QUINCY UGS	234	2	1	0	1	0
69	RPOUT FILLMORE_64TH STREET LCP SUB	132,635	3	1	0	0	0
70	RPOUT Standale_Parkside LCP 156	2,719	0	0	0	0	0
71	RPOUT BYRON CENTER-RAILSIDE LCP 375	10,625	0	0	0	1	0
72	RPOUT Rivertown_56th LCP 941	1,870	1	0	0	0	0
73	RPOUT STANDALE_STANDALE LCP 356	1,427	0	0	0	0	0
74	RPOUT LOGISTIC FELCH LCP 837	51,188	5	1	1	2	2
75	RPOUT SWAN CREEK MINING LCP 834 -OHL	53,286	4	0	0	0	0
76	RPOUT BUCHANAN-SANDY SHORES *outage card	36,925	0	1	0	0	0
77	RPOUT LOGISTIC FELCH LCP 329	2,296	0	0	1	2	1
78	RPOUT HOPKINS MONTEREY LCP 932	5,286	2	0	0	0	0
79	RPOUT MILL GROVE_ALLEGAN HYDRO LCP 378 *	11,607	4	6	5	1	0
80	RPOUT HAMILTON_HAWKEYE LCP 848B **OUTAGE	70,105	1	0	0	0	0
81	RPOUT HAMILTON-OVERISEL 665 788 889 918	2,951	1	0	0	0	0
82	RPOUT MERSON DUCK LAKE LCP 961 *outage c	59,516	3	1	5	2	0

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-21870

REVISED DIRECT TESTIMONY

OF

ANDREW R. SNIDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew R. Snider, 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 Executive Director of Electric Operations.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Business Administration from Davenport University in Grand Rapids, Michigan. I have been in the electric utility industry for more than 25 years. I began my full-time career with Consumers Energy in 1999 as an electric distribution designer and dispatcher. Through career progression in the Company's Engineering and Operations departments, I currently serve as Executive Director of Electric Operations, with responsibility for Customer Field Services, Electric Meter Operations, Underground Construction, and Contract Management teams. I have been directly involved in service restoration activities, fulfilling nearly all back office and leadership roles within the storm restoration/Incident Command System ("ICS") process dating back to my internship in 1998, supporting a back-office role for the largest storm in Company history. I served as a subject matter expert and project team member for the Outage Management System (OMS")/Responder project in 2008. I had the opportunity to represent Consumers Energy working on Florida Power and Light's system following Hurricane Wilma, and on National Grid's system following a severe winter storm. Today, I am supporting the Company's initiatives to improve service restoration activities.

Q. What are your responsibilities as Executive Director of Electric Operations?

A. I am responsible for leading Customer Field Services, Electric Meter Operations, Underground Construction, and Distribution Contractor teams.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I was the Company's witness for Service Restoration expense in Case No. U-21585.

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 service restoration spending, including technology and process enhancements. The test year is defined as May 1, 2026 through April 30, 2027. In the test year, the Company projects $165 million in service restoration operating and maintenance ("O&M") expense, which is based on the Company's actual 2024 Service Restoration expense, adjusted for inflation. The projected test year expense is detailed further in the Service Restoration Test Year O&M Expense beginning on page 20. Company witness Patrick D. Daly sponsors the inflation rates. The service restoration O&M expense and O&M expense associated with the Control/Dispatch Center consolidation project are included in Company witness Michael P. Kelly's Exhibit A-124 (MPK-14), and the Control/Dispatch Center consolidation capital costs are included in Company witness Quentin A. Guinn's Exhibit A-102 (QAG-3). Information Technology costs addressed in my testimony are included in Company witness Stacy H. Baker's Exhibit A-12 (SHB-4), Schedule B-5.1, line 3.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. No. I am not sponsoring any exhibits in conjunction with my direct testimony.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS

II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION

III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

IV. SERVICE RESTORATION RESILIENCY FUND

V. EXTRAORDINARY STORM ACCOUNTING

VI. TECHNOLOGY ENHANCEMENTS

VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY OUTAGE CAUSES

VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS

Q. How does the Company's service restoration program benefit customers?

A. Following service interruptions, the Company is committed to restoring service to customers quickly and safely, regardless of the weather. Service restoration activities 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, as the Company will be challenged to achieve further improvements in storm restoration service if it does not have timely rate recovery for the costs associated with such service.

Q. The Company has been challenged by stakeholders to improve restoration efficiency. Has the Company been able to demonstrate results?

A. As predicted by our climate change and weather modeling, customers experienced another record-breaking year in terms of response opportunities. The volume of interruptions in 2024 exceeded what mother nature delivered in 2023. In 2024, three catastrophic storms

and two large gray sky events that occurred back-to-back in January, affecting 293K customers in one week, were the primary events. Despite the increase in storm activity and interruption volume, O&M service restoration costs decreased year-over-year from 2023 to 2024 by 17% with the cost per interruption decreasing by 18%.

Additionally, the Company's System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs") improved 21.4 minutes to 155, and all-weather SAIDI improved from 913 to 502.6 minutes. The improvements in service restoration are a result of both the distribution system investments sponsored by Company witness Kelly and the CE-Way process of continuous improvement that I discussed in detail in Case No. U-21585, and as shown in further detail in Figure 1 below.

Figure 1
2023 – 2024 Service Restoration Performance

Metric	2023	2024	Percent Change
Total Interruptions	50,700	53,900	6%
Percent Restored within 24 Hours	87%	94%	8%
Service Restoration Expenses	$188 M	$156 M	-17%

Q. How was the Company's service restoration performance in Environmental Justice ("EJ") communities in 2024?

A. In 2024, the Company's All-weather service restoration performance, restorations made within 36 hours, in EJ communities was 98.9% compared to 97.7% in Non-EJ communities. All-weather restoration performance in EJ communities in 2024 was 1.2% better than the Company's system average.

Figure 2
2024 Restoration Performance in EJ and Non-EJ Communities

Restoration Performance Metric	Non-EJ Communities	EJ Communities
Average percentage of all-weather restorations made within 36 hours	97.7%	98.9%
Average percentage of Catastrophic restorations made within 48 hours	95.4%	94.9%
Average percent of gray sky restorations made within 24 hours.	94.5%	93.2%

Q. Has the Company started to incorporate considerations for EJ in their restoration practices?

A. Yes. In March of 2025, the Company developed reporting to provide increased visibility into the identification of circuits in EJ communities that are experiencing outages. This information is available in real time to the ICS teams and Grid Operators to assist with restoration prioritization.

Q. Is the Company satisfied with its holistic 2024 historical year performance?

A. The Company is proud of the more efficient use of service restoration expenses and quicker restoration times in 2024, but has several approaches aimed at further enhancing its performance that are detailed later in my testimony. The Company acknowledges that even with strong improvement in 2024, customers deserve an even more reliable grid than the Company had last year.

The Company, including the Service Restoration team that I'm part of, has a more aggressive goal for reliability as detailed in the Reliability Roadmap, which includes three resiliency stands.

1. Delivering reliability performance into the 2nd quartile of nationwide utilities.

2. Delivering a grid where no single outage event will affect more than 100,000 customers.

3. Delivering a grid where no customer will be without power for more than 24 hours following an outage event.

Achieving these goals remains a long-term work in progress; they serve as a useful guide to what the Company is building through this rate case.

Q. What weather challenges has the Company experienced so far in 2025?

A. The company has experienced two catastrophic storms already in 2025. Both storms affected more than 300,000 customers and occurred just six weeks apart. The first event was a historic multi-wave storm event that affected much of the state of Michigan from late March into early April that meteorologists from the National Weather Service called, "the worst ice storm in modern times."[1]

The event was so destructive that on March 31, Governor Whitmer declared a state of emergency in 10 counties in northern Michigan (Otsego, Oscoda, Montmorency, Presque Isle, Emmet, Charlevoix, Cheboygan, Crawford, Mackinac, and Alpena) and later extended the declaration to cover Alcona and Antrim counties. Several extreme weather factors, including freezing rain, damaging winds, thunderstorms, and 13 confirmed tornadoes made for a long and challenging restoration effort. Further detail on the timing and customer impact of the storms is detailed in Figure 3 below.

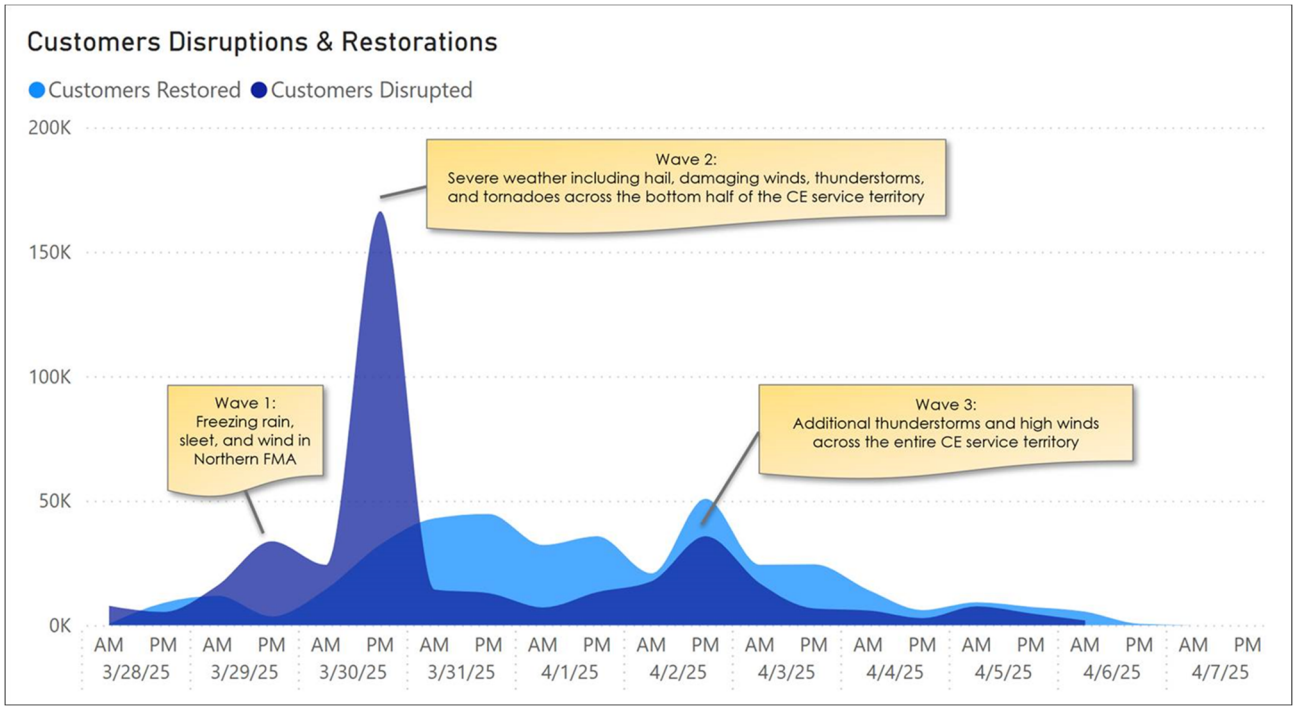
The event resulted in more than 8,500 outage incidents impacting over 380,000 Consumers Energy customers, the 7th largest storm by outages in the Company's history. Icing on distribution and transmission lines, measuring up to 1.5" in certain areas, began March 31 and remained into Thursday, April 3, continually bringing down trees, power

[1] Doyle, Annie. "'A Generational Storm': Northern Michigan Ice Storm Was Worst in over 100 Years." Petoskey News-Review, 3 Apr. 2025.

poles, and power lines, and delaying restoration crews' ability to make repairs due to the weight of the ice on the lines. The storm's severity and the subsequent evacuation of certain areas underscored the importance of Consumers Energy's enhanced Control Center Consolidation plan as discussed in section VII of my testimony.

The total cost of the storm is projected to exceed $133 million (O&M and Capital), which is a significant portion of the Company's 2025 service restoration authorized spend from Case No. U-21585.

Figure 3
March/April 2025 Catastrophic Storm Disruptions and Restorations



The second event affected over 334,000 customers just six weeks after the historic icing event. On the evening of May 15th, a severe line of thunderstorms struck the State, leaving a wake of destruction. The massive line of storms produced 11 tornados and hurricane strength wind gusts from Holland to Battle Creek, ultimately resulting in over

830 broken poles and 91 miles of conductor that required replacement. Total costs (O&M and Capital) from this event are estimated to exceed $60 million.

Q. What has the Company learned from the recent catastrophic storms in Michigan and how is this reflected in your testimony?

A. The recent catastrophic storms have demonstrated the urgent need for timely rate recovery to keep the power on for customers, businesses, and communities, so the Company can respond to the 'New Normal' of severe storms in Michigan.

The climate and weather modeling has been acutely prescient in predicting increased severe storms in the Company's service territory: the *Scenario and Investment Planning* section of the Reliability Roadmap included warnings of increased thunderstorms and 'Other' storms (including ice conditions) in the northwestern and southern parts of the Company's service territory, primarily occurring during the winter when outages are typically more difficult to restore.

The modeling goes on to predict that this type of weather will become more frequent in the coming years, meaning the Company will likely have to protect and restore its customers from similar events on 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.

Q. Please provide a brief overview of the remainder of your testimony.

A. Section II provides a detailed overview of Consumers Energy's current event classification, resource identification, and pre-storm communication as well as several other operational and budgeting recommendations from the audit conducted by Liberty Consulting Group

("Liberty"). Section III builds off the recommendations by Liberty, and details how the Company's bridge period and test year O&M was calculated in this case.

Sections IV and V include two new proposals to ensure the Company will have the necessary rate recovery needed to continue providing both timely storm restoration and a safe and reliable grid.

Sections VI, VII, and VIII detail the ongoing investments and process improvements being made to further foster Consumers Energy's storm restoration efficiency through upgrades to its digital emergency response system and consolidation of dispatch operations.

II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION

Q. Please describe the process leading up to the audit performed by Liberty.

A. The Commission opened Case No. U-21305 in October 2022 after severe weather in August of that year caused many long power outages, downed energized utility lines across the state, and threatened public safety. In its order, the Commission instructed its Staff ("Staff") to hire a consultant to audit the electric distribution systems of Consumers Energy and DTE Electric Company. The Commission directed the audit to consist of physical inspection of the utilities' distribution system infrastructure and investigation of the utilities' organization, staffing, and resources used to operate and maintain their distribution systems and restore power when service is interrupted by severe weather. Staff hired Liberty to audit the two utilities' distribution systems, and the Company worked with Liberty to promptly answer all written questions and transparently meet in numerous interviews throughout 2023 and 2024. The Company also arranged Liberty's physical inspection and accompanied them as its auditors inspected pole locations, substations, the Cadillac headquarters, and the Jackson distribution center. Following this process, Liberty

released their final Utility Distribution Audit Report for the Company in two parts ("Final Report") on September 23, 2024.

In response to Liberty's Final Report and stakeholder comments, the Company filed comments and replies. Many recommendations in Liberty's report were aimed at improving the Company's service restoration performance and had obvious merit, which led the Company to begin making changes addressing these recommendations while it awaits a final order in Case No. U-21305. As these changes impact proposals and expenses in this case, I am updating stakeholders and the Commission on the Company's progress.

Q. Please describe the findings related to Pre-Event Planning from the Final Report.

A. Part II of the Final Report included three recommendations specific to Pre-Event Planning beginning on page 116, including:

- **Recommendation 4**: Better assure more tailored and accurate outage modeling results by codifying and analyzing predicted versus actual outage events.
- **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.
- **Recommendation 6**: Capture and analyze data associated with external resource requests. [2]

Q. Please provide further details on Liberty Recommendation 4.

A. Recommendation 4 proposes the Company evaluate its current outage model for effectiveness and consider developing a more robust product in-house or through a third-party vendor to provide more useful and impactful results.

[2] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 116 (Sep. 23, 2024).

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 4?

A. The Company agrees with the Final Report recommendation that accurate outage modeling is critical for restoration staffing and planning for forecasted storm events and believes that more accurate outage predictions can improve the Company's storm restoration performance, including wire-down response.

The Company is currently working to improve its outage modeling results through two additional initiatives, which will enable the Company to make improvements in outage modeling capabilities:

- **New Third-Party Outage Model** – The Company is currently evaluating third-party vendor technologies that could potentially improve upon its outage modeling capabilities currently provided by IBM. The Company is currently in a request for proposals phase with third-party vendors, which would merge its weather and outage modeling services. The Company expects to select a third-party provider in May 2025, and the Company expects that it will be able to leverage the outputs of the third-party vendor's model later in 2025.

- **New In-House Outage Model** – The Company plans to internally develop a standalone outage prediction model in partnership with the University of Michigan. This in-house model would provide the Company with another set of data to compare against outputs from the third-party outage model. Currently, this model development is in its preliminary stages and is scheduled to be operational by late 2025. Once developed, the Company would run the in-house model concurrently with the third-party vendor model to compare results and test its output to determine the in-house model's effectiveness and for potential upgrade and/or waste elimination opportunities. In the testimony of Company witness Scott A. McPhail, weather stations will be added to provide more granular weather data that will eventually feed into the in-house outage model offering improved predictive capabilities.

In summary, the Company agrees with this recommendation and has a series of technology investment plans that will enable the Company to improve its outage modeling prediction accuracy beginning in 2025. Furthermore, the Company will continue to assess the

predictions from these capabilities against actual outages to identify areas of improvement to drive better prediction outcomes for future storms.

Q. Please provide further details on Liberty Recommendation 5.

A. Recommendation 5 proposes the Company make the act of event classification a catalyst to groups involved in restoration to prepare to address the needs associated with the anticipated impacts of the event and change, as necessary, after storm arrival, to reflect new weather-related developments and resultant changes.

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 5?

A. The Company has appropriate processes and procedures in place to meet the intent of this recommendation. The Company understands the intent of this recommendation is to enable efficient storm restoration preparation performance by potentially improving early storm event classification, resource needs identification, and pre-storm communication processes and procedures. While the Company welcomes opportunities to improve its storm response preparation processes and procedures, there is more to the Company's current processes than what is reflected in the Final Report for event classification, resource identification, and pre-storm communication.

Q. What is the Company's current process for event classification, resource identification, and pre-storm communication?

A. When preparing for a storm, the Company predicts an estimated number of outages from its current IBM outage prediction model that will be experienced because of the potential storm event.

The next step is to use its Catastrophic Crewing ("CatCrew") tool to develop an estimate of how many resources will be needed to complete the restoration within the MPSC's Service Quality and Reliability Standards for Electric Distribution Systems. Based on this outage prediction and estimated resource needs, the Emergency Response team then makes and communicates an event classification for the potential storm event. On page 95 of the Final Report in Part II, Liberty included a table with the storm incident classification levels from the Company's Storm Restoration Manual ("SRM"). Initial storm classifications are documented on an ICS Form 201 for each storm event, which is available to all storm responders in the ICS organization.

Q. Concerning the Company's current event classification and resource identification processes, what else should stakeholders and the Commission know when evaluating the Final Report findings on these issues?

A. There are several aspects of the Company's current event classification and resource identification processes and procedures that should be considered:

- Part II of the Final Report states on page 96 that "Analysis showed that management did not classify any of these events prior to event start date."[3] All initial storm classifications are documented on the ICS Form 201.

- The Final Report goes on to state on page 96 that "Consumers' event level classifications provide no specific guidance as to potential resource requirements." In fact, predicted customer outages and estimated resource needs dictate storm event classification; storm event classification does not dictate resource needs. In other words, storm event classification can only happen when resource needs and customer outages have been estimated. Additionally, the model being developed by the Company in partnership with the University of Michigan will use sophisticated machine-learning techniques to correlate historical outages to their causation (i.e., weather, topographic data, forestry work, reliability work, etc.). This will produce a more accurate and more localized outage forecast due to incoming weather that allows better planning to secure and pre-stage resources for faster restoration.

[3] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

- Part II of the Final Report states on page 113 that "The storm team communicates internally to activate the required resources and processes without attaching value or significance to the determination and communication of an event's classification. This view should change."[4] The value and significance of a storm event is the predicted customer outages and estimated resource needs, not the storm incident level by itself. While storm event classification may be useful as a trigger for certain storm related activities, the predicted customer outages and estimated resource needs is the foundational information that drives all storm restoration related activities.

Q. Please provide more details on the Company's current storm communication process.

A. The Company currently plans for storm events on a weekly basis in advance to prepare for a weather event's impact and communicates accordingly with its stakeholders. As recommended in the Audit, in November 2024 the Company hired a full-time Meteorologist to provide tailored weather forecasts, specific to the Company's distribution grid and the state of Michigan, every morning to stakeholders across the Company. In terms of timing, every week the Company prepares for the subsequent week's potential storm responders from an ICS perspective. This cadence includes an initial indication of what ICS Level the storm may be based on meteorological forecasts. Storm preparedness communications begin every Thursday and storm preparation related information is documented in ICS Form 201. Additionally, every day there is a Daily Communication Report that provides storm preparation and planning updates to relevant stakeholders across the organization. This information includes any changes to initial forecasts and updates to previous resource needs.

[4] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 113 (Sep. 23, 2024).

Q. Concerning the Company's current storm communication processes, what else should stakeholders and the Commission know when evaluating the Final Report findings on this issue?

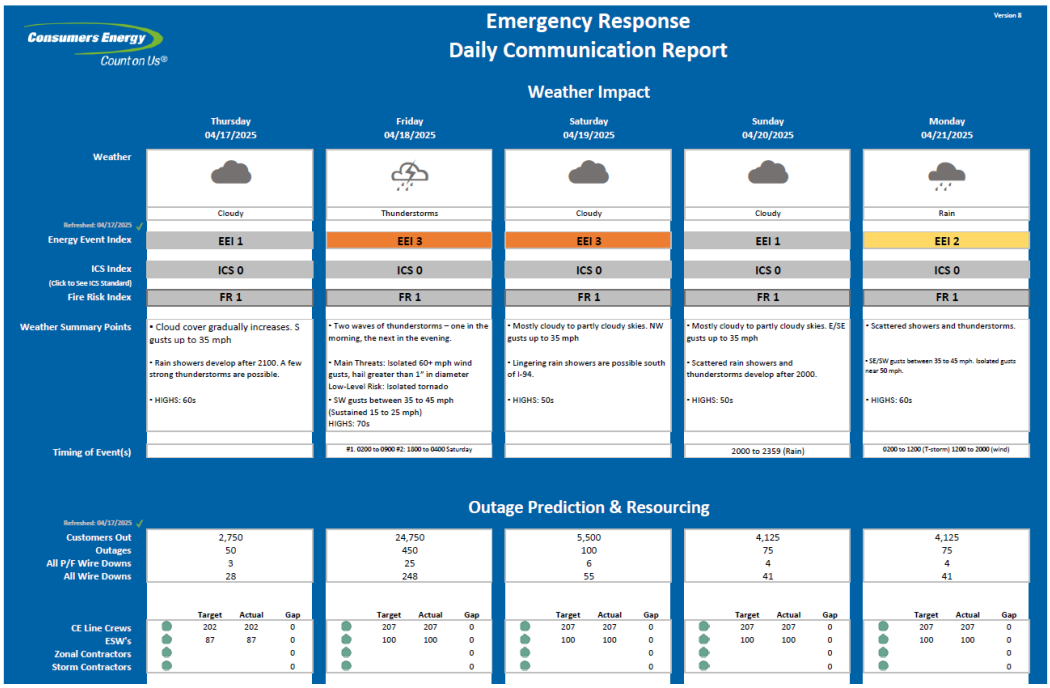
A. There are several aspects of the Company's current storm communication processes and procedures that should be considered:

- Again, Part II of the Final Report states on page 96 that "Analysis showed that management did not classify any of these events prior to event start date. Neither did it change any classification for these events once made.[5]" As described above, storm event preparation and planning updates are communicated daily to all stakeholders via the Daily Communication Report. Based on changes communicated in this report, including event classification changes, appropriate storm response related actions are made. The Final Report does confirm this in another statement on page 96 that "Restoration Management did . . . begin in late 2023 to publish a Daily Communication Report that presents a five-day look ahead that contains, among other useful information, outage prediction and resource requirement data and an ICS incident level prediction. See Figure 4 below."[6]

Furthermore, the Company does correct the ICS Level categorization data when it is finalized for MPSC reporting purposes. For example, if a storm is initially reported as affecting an estimated 190,000 customers and subsequent meter-ping data determines that only 180,000 customers were affected, that information will be shared with the MPSC as well if there is a relevant incident level adjustment. These updates are done across normal, gray sky, and catastrophic storm conditions.

[5] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).
[6] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

Figure 4
Daily Communication Report Example



Consumers Energy — Count on Us®

Emergency Response
Daily Communication Report

Version 8

Weather Impact

	Thursday 04/17/2025	Friday 04/18/2025	Saturday 04/19/2025	Sunday 04/20/2025	Monday 04/21/2025
Weather	Cloudy	Thunderstorms	Cloudy	Cloudy	Rain
Refreshed: 04/17/2025 ✓ Energy Event Index	EEI 1	EEI 3	EEI 3	EEI 1	EEI 2
ICS Index (Click to See ICS Standard)	ICS 0	ICS 0	ICS 0	ICS 0	ICS 0
Fire Risk Index	FR 1	FR 1	FR 1	FR 1	FR 1
Weather Summary Points	• Cloud cover gradually increases. S gusts up to 35 mph • Rain showers develop after 2100. A few strong thunderstorms are possible. • HIGHS: 60s	• Two waves of thunderstorms – one in the morning, the next in the evening. • Main Threats: Isolated 60+ mph wind gusts, hail greater than 1" in diameter Low-Level Risk: Isolated tornado • SW gusts between 35 to 45 mph (Sustained 15 to 25 mph) HIGHS: 70s	• Mostly cloudy to partly cloudy skies. NW gusts up to 35 mph • Lingering rain showers are possible south of I-94. • HIGHS: 50s	• Mostly cloudy to partly cloudy skies. E/SE gusts up to 35 mph • Scattered rain showers and thunderstorms develop after 2000. • HIGHS: 50s	• Scattered showers and thunderstorms. • SE/SW gusts between 35 to 45 mph. Isolated gusts near 50 mph. • HIGHS: 60s
Timing of Event(s)		#1. 0200 to 0900 #2: 1800 to 0400 Saturday		2000 to 2359 (Rain)	0200 to 1200 (T-storm) 1200 to 2000 (wind)

Outage Prediction & Resourcing

	Thursday 04/17/2025	Friday 04/18/2025	Saturday 04/19/2025	Sunday 04/20/2025	Monday 04/21/2025
Refreshed: 04/17/2025 ✓ Customers Out	2,750	24,750	5,500	4,125	4,125
Outages	50	450	100	75	75
All P/F Wire Downs	3	25	6	4	4
All Wire Downs	28	248	55	41	41
	Target / Actual / Gap	Target / Actual / Gap	Target / Actual / Gap	Target / Actual / Gap	Target / Actual / Gap
CE Line Crews	202 / 202 / 0	207 / 207 / 0	207 / 207 / 0	207 / 207 / 0	207 / 207 / 0
ESW's	87 / 87 / 0	100 / 100 / 0	100 / 100 / 0	100 / 100 / 0	100 / 100 / 0
Zonal Contractors	/ / 0	/ / 0	/ / 0	/ / 0	/ / 0
Storm Contractors	/ / 0	/ / 0	/ / 0	/ / 0	/ / 0

Q. Please provide further details on Liberty Recommendation 6.

A. Recommendation 6 proposes the Company track resource requests from specific contractors (or mutual assistance), request timing, and what resources were provided to assist in post-event analysis, process improvement, and internal training.

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 6?

A. Since the execution of Consumers Energy's storm contracts which began on June 1, 2023, the Company has implemented or refined mechanisms to track, manage, and retain requests for resources to respond to service restoration events. These mechanisms include:

- A scorecard of all storm contractors to assist in acquiring resources by ranking the storm contractors in terms of lowest cost, proximity to Jackson, MI, number of full-time employees ("FTE") available to respond, and union/non-union status of their FTE's.

- A managed PO Box where all communications pertaining to requests for assistance are kept.

- Centralized Microsoft Teams database maintained by the Company's Emergency Response organization. This database contains all current and past storm rosters of storm response contractors acquired since January 2022 to present, training standards, and documentation for Contractor Personnel Specialists responsible for acquiring storm response contractors.

- Bi-annual training for Contractor Personnel Specialists, along with on-demand training as standards are updated or improved.

- Ensuring the Company's storm response contractors have completed Consumers Energy's requirements for onboarding in ISNetworld prior to arrival on the system.

- Developing, designing, and delivering training to Company representatives responsible for oversight of storm contractors, including daily validation of crews and equipment acquired and working on Consumers Energy's system.

Q. Please describe the findings related to restoration budgeting from the Final Report.

A. Part II of the Final Report included two recommendations specific to restoration budgeting beginning on page 117[7]:

- **Recommendation 9:** Re-baseline restoration budgeting to produce estimates that fully and realistically consider expected needs; and

- **Recommendation 10:** Explore means to balance Company and customer interests in addressing highly volatile restoration costs following completion of the preceding recommendation addressing budgeting for storm restoration.

Q. Please provide further details on Liberty Recommendation 9.

A. Liberty's Recommendation 9 is a result of their Conclusion 15 in Part II, Chapter III, pages 114 to 115 which concludes:

> It is not clear how a five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages. [8]

[7] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).
[8] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 114-115 (Sep. 23, 2024).

Recommendation 9 states that reliance on the five-year average to fund service restoration should end.

> Reliance on five-year historical costs to establish restoration budgets should end. Those responsible for managing restoration cannot be held properly accountable for work or costs performance if established budgets are known to be unrealistic, fail to account for weather volatility, include anomalous weather years within the five-year measurement period, or rely on contributions from other parts of the organization to accommodate not just expected, but essentially certain overruns.[9]

Recommendation 9 also proposes the Company address how these system investments and weather conditions will change through the timeframe included in the Reliability Roadmap report.

Q. Please provide further details on Liberty Recommendation 10.

A. Recommendation 10 notes that service restoration expenses should theoretically trend downward in response to reliability and resiliency investments. However, those improvements may be offset by worsening weather:

> Most significantly, the use of five years of historical restoration costs as a benchmark for sharing between the Company and customers ignores the fact that the system will steadily respond better as time passes to outages that require material restoration. It should not be taken for granted that escalation and worsening weather will overcome the reliability and resiliency gained by billions of dollars spent over that historical period….[10]

Short of completing a full analysis that normalizes weather conditions and quantitatively assesses how the Company's investments will interact with weather conditions to impact storm restoration costs, as Liberty suggested in Recommendation 9, Recommendation 10

[9] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).
[10] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 118 (Sep. 23, 2024).

includes a deferral alternative. Liberty noted that other state regulatory commissions have found deferral an effective means for permitting recovery of excess storm costs coupled with a reasonableness and prudence review.

Q. How is the Company's Service Restoration proposal responsive to concerns raised by Recommendations 9 and 10?

A. The Company's proposed bridge period and test year O&M expense aligns with Final Report recommendations by ending reliance on a five-year historical average and instead basing the projected expense on the Company's 2024 actual Service Restoration expense adjusted for inflation. The Company believes this approach provides the most accurate benchmark based on projected service restoration performance requirements. The Company's Reliability Roadmap, included as part of this case as Exhibit A-129 (MPK-19), already provides a normalized weather modeling forecast for the three scenarios recommended by the Final Report. Further detail on the projected O&M spend, based on 2024 actuals, is included in the following section of my testimony.

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 bridge period is $214.3 million and the projected expense for the test year in this case is $165.2 million as shown in Exhibit A-124 (MPK-14), line 22.

Q. How did the Company determine this amount for projected service restoration O&M expenses for the test year?

A. Part II, Chapter III, page 110 of the Final Report states that:

> Consumers plans very large capital and O&M expenditures to improve system reliability and resiliency over the course of five years. It has already achieved improvements to date. Those improvements should, all else being equal, lower restoration costs for a system steadily and materially improving in reliability and resiliency, **making historical costs a lagging, and not a leading indicator of likely costs.** Factors that make all else unequal include escalation that will affect the unit cost of each piece of equipment installed and each quantity of work performed. Should recent storm frequency and magnitude trends reverse, more extreme weather will also drive costs upward, albeit moderated by an increasingly "strong" system. Storm restoration costs have proven highly volatile throughout the industry.[11]

Given that 2024 O&M spending is a lagging indicator (although with far less lag than the five-year average), the bridge period and test year funding was calculated by inflating the historical year 2024 for the years 2025, 2026, and 2027. For the bridge period, the calculation includes all of calendar year 2025, plus four months of 2026, the sum of which equals the bridge period amount of $214.3 million. The calculation for the test year considers eight months of the year 2026 and four months of the year 2027, the sum of which equals the test year amount of $165.2 million. The inflation rates for the years mentioned above are sponsored by Company witness Daly.

[11] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024) (emphasis added).

Q. What is the most recent five-year average for Service Restoration, and would that amount be adequate for the Test Year in this case?

A. Service Restoration has been underfunded in each of the previous five years, for a total funding gap of $351 million. The most recent five-year average from 2020 through 2024 would have produced a test year total of approximately $148 million that the Company projects would be insufficient to deliver the improved service restoration that customers deserve. To illustrate the point, the March/April catastrophic storm that I described earlier is projected to cost at least $133 million dollars combined O&M and Capital. As explained in detail in Section I of my testimony, the actual expenses from the calendar year 2024 were $156 million, which were sufficient for the Company to deliver improved performance on all restoration metrics. As the Company faces increasingly severe weather, and progressive service restoration improvement metrics detailed in the Commission's February 27, 2025 Order in Case No. U-21400, relying on a backward-looking average that has been explicitly rejected by an independent audit threatens to undo the progress made by the Company.

Q. Why are 2024 historical costs a reasonable benchmark for projected service restoration expense?

A. Prior year spending is the most accurate benchmark of trending weather and current system capabilities, based on the unpredictable weather explained in the *Scenario and Investment Planning* section of the Company's Reliability Roadmap beginning on page 18. This fact is recognized in the order released on March 13, 2025 in Case No. U-21400 where the Commission decided to benchmark all weather SAIDI on current year performance rather

than the five-year average, as current year performance better reflects recent trends and customer experience.[12]

A study, beyond the Reliability Roadmap, specific to annual restoration spending, would be theoretical given the high volatility of key variables. The Company's recommended approach is to re-baseline to the most recent year, which most accurately represents all variables in their current state. Further, through the creation of the Resiliency Fund outlined in Section IV, the Company ensures every dollar is allocated specifically for customer service restoration or returned to customers as a credit.

Q. Has the Company been prudent with restoration dollars by increasing efficiencies?

A. Yes. The Company's results are demonstrated by its historic year's performance and documented in Service Quality and Reliability Standards filings and discussed in Section I of my testimony. In 2024, the duration of catastrophic storms in the Company's service territory, as measured by the average length of storm days, was 3.3 days compared to a five-year average of ~~5.4 days~~ 5.5 days. This accounts for a 2.1 day or 61% reduction in catastrophic storm duration resulting in a greatly improved customer experience.

Liberty also took note of our performance trend since 2017 concluding in Part II, Chapter III, Pages 113 through 114 of its audit:

> Consumer's restoration performance, measured by the average duration of classified storm types, **shows marked improvement in recent years across all storm classifications except for Catastrophic.**[13]

[12] See Case No. U-21400, February 27, 2025 Order, page 30 ("The Commission agrees that performance on this [all-weather SAIDI] metric should be measured for the previous year only.")
[13] Case No. U-21305, Liberty Audit Final Report Consumers Energy Part II, page 113-114 (Sep. 23, 2024) (emphasis added).

In terms of catastrophic performance, and the data set studied by Liberty, recent storms had caused more customer interruptions resulting in longer durations trends through 2023. Liberty noted in Part II, Chapter III, page 110:

> A Catastrophic storm's defining characteristic, a minimum of 10 percent of customers affected, ensures a longer restoration period as compared with those of smaller storms. The unbounded upper limit on customers affected also tends to produce a much greater variation in the numbers of affected customers. The much longer duration of Catastrophic storms and greater variations in duration therefore come as expected.[14]

Q. How does the Company's proposal align with the Liberty Audit recommendations for Service Restoration?

A. As mentioned earlier in my testimony, the proposed test year O&M proposal reflects the 2024 actual Service Restoration expense adjusted for inflation, which the Company believes provides the most accurate benchmark for service restoration requirements.

IV. SERVICE RESTORATION RESILIENCY FUND

Q. What is the Service Restoration Resiliency Fund?

A. The Resiliency Fund ensures that every customer dollar allocated for service restoration is used for service restoration or returned to customers as a credit. The Resiliency Fund is a reserve of surplus service restoration dollars from any prior year that will be used as the first source of funds when actual costs for service restoration exceed base spend levels. The fund will be capped at $30.7 million in the test year, with any dollars exceeding those levels refunded to customers through a bill credit.

[14] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024).

Q. Please provide an example of how this fund would operate.

A. If this fund is approved, any unspent dollars from the approved amounts for the test year would be transferred to the Service Restoration Resiliency Fund. Those dollars can be used to support service restoration expenses in future years when additional funds are needed and would function as the first option to fund any restoration activity beyond base funding levels. Please see Company witness Foster's testimony on page 15 for more detail on the accounting of this request.

Q. Please walk through Scenarios 1, 2, and 3 from Figure 5 below.

A. **Scenario 1** shows an underspend of $40 million dollars in the test year resulting in a transfer of $30.7 million to the Resiliency Fund and a customer refund of $9.3 million. Since the Resiliency Fund cap is exceeded by this underspend amount, the remaining $9.3 million will be refunded to customers.

Scenario 2 shows an underspend of $20 million dollars in the test year resulting in a transfer of $20 million to the Resiliency Fund to be used for service restoration expenses that exceed base spending. Since the Resiliency Fund cap is set at $30.7 million, the Resiliency Fund can accrue an additional $10.7 million before there is a customer refund.

Scenario 3 shows an overspend of $5 million in the test year, resulting in no transfers to the Resiliency Fund.

Figure 5 - Resiliency Fund Year One Example

Scenario	Base Funding Amount	Restoration Spend	Resiliency Fund Balance	Customer Refund
1	$165M	$125M	$30.7M	$9.3M
2	$165M	$145M	$20M	$0
3	$165M	$170M	$0	$0

Q. How and why was the $30.7 million cap limit set?

A. The cap limit was based on the average O&M costs for a catastrophic storm for the past three historic years (2022, 2023, and 2024). The average storm cost was then adjusted for inflation based on the 2.4% inflation rate supported by Company witness Daly as part of this case. Because the weather is unpredictable, the Company set this limit to ensure that the fund only preserves the dollars needed to respond to a single potential catastrophic event, after which customers would see a financial benefit from the Company's efficiency.

Q. Is there a precedent from other states for setting a cap on reserve funds for storm restoration?

A. Yes. The Massachusetts Department of Public Utilities ("DPU") approved a proposal by National Grid to increase the available storm fund contribution to reflect average annual storm expenses for the previous five fiscal years. Under the recently revised proposal, for any storm in which National Grid incurs more than $1.80 million in incremental O&M costs, National Grid is permitted to access a storm fund for the deferred recovery and reimbursement of the portion of the costs that exceed $1.80 million up to $30 million for a single event. In its order approving National Grid's proposal, the DPU noted the proposed storm fund will provide for adequate recovery of storm costs while promoting rate stability. While the Company's proposal differs from the Massachusetts mechanism, which includes a surcharge to collect a set amount of storm costs through rates, the concept of setting a cap on funds reserved for future use is similar.

Q. How is this proposal different from how underspends for service restoration are handled currently?

A. Currently, in the event of an underspend for Service Restoration, the Company would re-allocate the O&M resources to other projects with no guarantee that customers would see any reimbursement. If approved, this Fund would both earmark approved funds for service restoration in the years to come when the need arises or be returned to the customer.

Q. What is the likelihood that there will be any underspend in the test year in this case?

A. Re-baselining suggests there is a higher likelihood of underspend. The Company knows that weather is unpredictable; however, as Liberty noted, weather volatility should be at least partially offset by system improvements.[15] Coupled with the Company's restoration improvements, the Company maintains that there is an increased likelihood of underspend from the prior year baseline. It really depends on what nature delivers. Consumers Energy estimates that, over time, reliability investments will ease restoration spending needs. When the Company inevitably spends less than projected, customers are protected by the designed nature of the Resiliency Fund.

Q. Why is the Service Restoration Resiliency Fund good for customers?

A. The Resiliency Fund comes at no additional cost to customers—it is simply a rainy-day savings plan. The Resiliency Fund ensures all dollars allocated for service restoration are spent on service restoration or refunded. This proposal, coupled with re-baselining Service Restoration to prior year actuals, mitigates the need for expensive speculative studies on how the system will perform given the multitude of variables, while ensuring that **all** savings from prior year system improvements and efficiencies will be saved for outlier

[15] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 115 (Sep. 23, 2024).

restoration expenses in a future year. Together with annual re-baselining, customers will see immediate benefits from any year's savings in the next baseline, while savings are also captured in the Resiliency Fund for no other reason than to benefit customers, literally, on a rainy day.

V. EXTRAORDINARY STORM ACCOUNTING

Q. Please describe the Company's proposed Extraordinary Storm Accounting or "ESA."

A. ESA allows the Company to use deferred accounting for service restoration costs for extraordinary storms that exceed base spending levels. The Company defines "extraordinary storms" as storms that cause at least 300,000 customer outages over a seven-day period or that result in a State of Emergency declaration from the Governor's office. A recent example of such a storm is the March/April catastrophic storm cited in Section I of my testimony. Under the Company's proposal, expenses in response to extraordinary storms would qualify for deferred recovery.

Q. Please provide an example of how ESA would operate.

A. If the Company experiences any emergency storm(s) described above that drives the actual spend higher than the service restoration base spending level (as well as any dollars available through the Resiliency Fund, if approved), the Company would seek deferred recovery from the Commission by demonstrating the reasonableness and prudence of the restoration expenses in a future rate case. Overspend costs not related to an emergency storm would not be eligible for recovery under ESA.

As detailed above, spending below the approved spending level would be directed back to service restoration or customer refunds through the proposed Resiliency Fund (if approved).

Q. How was the 300,000 customer outage over a seven-day period or State of Emergency declaration threshold determined?

A. The emergency storm threshold was designed to apply to uncommon storms, based on objective metrics or independent third-party assessment, which cause the most restoration work and costs to the Company. In reviewing historical restoration data, storms causing at least 300,000 customer outages are rare occurrences that also correlate to a long restoration time and high costs. The Company has only recorded 13 storms with at least 300,000 outages, and restoration efforts from those storms have averaged seven days in restoration duration.

While the outage count is a useful proxy for restoration time and cost, it is not the only indicator of damaging events. Isolated natural disasters, such as the tornadoes that struck Kalamazoo in 2023, did not cause many outages, but caused considerable damage to distribution assets, leading to a three-day restoration. The addition of an emergency declaration from the Governor's office allows for an independent assessment outside of the Company's control to also qualify an event as an "emergency storm."

Q. Why is the proposed ESA necessary?

A. Extraordinary storms, which present challenging restoration conditions and cause significant damage to Company assets, are the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration operations. As explained earlier in my testimony, the March/April storms qualify as extraordinary storms that drained most of the service restoration O&M budget for 2025. When these storms pass through the Company's service territory, even perfect execution of pre-planning and restoration procedures can still result in a costly, multi-day restoration effort costing over

$100 million. As disruptive and costly as these storms are, they are fundamentally unpredictable; it is impossible for the Company to know with any degree of certainty how many of these storms will pass through its service territory, and therefore impossible to accurately predict the resources needed to respond to them. Requiring the Company to bear the full brunt of their impact in a single year without allowing for deferred storm accounting, which recognizes the heavy costs the Company incurs to safely and quickly restore power after extraordinary storms like these, is not only unreasonable but also counterproductive to ensuring a reliable and resilient grid. Preparing for a future where weather events like the March/April storms are more frequent requires establishing deferred accounting where the Company can apply for timely rate recovery in response to these events.

Q. What were the findings of the Liberty Final Report related to deferred recovery for excess storm costs?

A. Liberty noted the current utilization of deferral accounting by other commissions in Part II; Chapter III, Pages 118-119 of the Final Report, stating,

> Deferral accounting for excess storm costs may offer a solution for avoiding customer costs for adverse weather that does not materialize, while preventing significant Company economic loss when such weather requires significantly more than costs included in revenue requirements for ratemaking purposes. Other commissions have found deferral an effective means for permitting recovery following some form of reasonableness and prudence review that considers conditions faced and the effectiveness of efforts undertaken to address them.[16]

[16] Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 118-119 (Sep. 23, 2024).

Q. Do other states use deferred accounting for O&M costs caused by severe weather?

A. Yes. New Jersey is one example. In 2021, the New Jersey Board of Public Utilities ("BPU") authorized deferred accounting for storm costs in BPU Docket No. ER21050823, with automatic qualification for specific storms and the ability for utilities to petition for approval for other storms. The Board determined that the utilities' costs for an individual storm automatically qualify for deferred accounting if they incurred incremental costs of $300,000, and the storm caused 10% or more of the customers located in the service territory to be without electric service. South Carolina is another example. In response to standalone storms that devastated large portions of the Carolinas, the Public Service Commission of South Carolina in 2019 authorized deferred accounting for incremental storm damage expenses in Docket No. 2019-26-E.

Q. Please walk through Scenarios 1, 2, and 3 from Figure 6 below.

A. **Scenario 1** shows an overspend of $30 million, driven by a $50 million emergency storm and resulting in a $30 million deferred recovery request. Since the emergency storm costs exceed the difference between the base funding amount and the actual restoration spend, the Company will ask for deferred recovery for the difference. The Company will provide the Commission with the total expenses in response to the emergency storm including justification for their reasonableness and prudence.

Scenario 2 shows no difference between the base funding amount and the total spend. Since the calendar year budget was adequate to the restoration needs for the year, there will be no ESA despite the presence of an emergency storm.

Scenario 3 shows an overspend of $10 million but since the overages are not a result of an emergency storm, the ESA will not be available.

Figure 6
ESA Year One Example

Scenario	Base Funding Amount	Total Restoration Spend	Emergency Storm Costs	ESA Deferred Recovery Amount
1	$165M	$195M	$50M	$30 M
2	$165M	$165M	$50M	$0
3	$165M	$175M	$0	$0

Q. What is the process in a year where customers experience emergency storm(s) and spending is less than base funding?

A. All underspend in service restoration will be allocated to the Resiliency Fund up to the cap of $30.7 million. Once the cap is reached, customers will be refunded as a bill credit as described in section IV.

Q. What if the Resiliency Fund has a balance large enough to cover overages caused by catastrophic storms?

A. In this circumstance, the Company will not use ESA. Resiliency Fund dollars will be used first to supplement overages in restoration spending.

Q. Can ESA function independently without the Resiliency Fund?

A. Yes. ESA can function independently. If approved, the Resiliency Fund would serve as the first source of excess service restoration funds in the event of an overspend; however, it is not required for the Company's ESA proposal.

Q. How is ESA different from the Service Restoration Cost Sharing Mechanism ("SRCSM") proposed in Case No. U-21585?

A. ESA creates both a higher threshold for deferred recovery than the SRCSM as well as a process for Commission approval and vetting of service restoration expenses. ESA is only available for "extraordinary storms," defined to limit the eligible expenses for deferred accounting to storms that cause the most damage to customers and restoration work for the Company. By narrowing the scope of storms that qualify for deferred recovery, the Company can focus on meeting Commission-defined Service Quality and Reliability Standards within the base spending levels and have faith that timely rate relief will be available when needed. Secondly, ESA gives the last word on deferred recovery to the Commission. When deferred costs are considered for recovery in a future case, ESA will require the Company to demonstrate that all expenses in response to extraordinary storms are reasonable and prudent. The explicit inclusion of Commission approval is intentional and reflects the Company's confidence in its service restoration practices and desire for a collaborative process to address future emergency storms.

VI. TECHNOLOGY ENHANCEMENTS

Q. Are there any Capital investments in technology that support Service Restoration?

A. The Company is continuing to enhance the digital emergency response system by completing the previously planned CatCrew and Advanced Distribution Management System ("ADMS") enhancements, as approved in Case No. U-21389. The Company is also resolving the software obsolescence concerns of its integrated Tools for Operations Application ("iTOA"), as referenced on page 39 of Company witness Baker's testimony and Exhibit A-84 (SHB-1), as approved in Case No. U-21585 The Company is proposing a $825,700 capital and $660,500 O&M investment in the test year for the development of

machine learning / Artificial Intelligence ("AI") digital tools to specifically support storm response, as described on page 52 of Company witness Baker's testimony and Exhibits A-12 (SHB-4), Schedule B-5.1 and A-19 (SHB-3).

Q. How will the digital tools and utilization of Machine Learning and AI benefit customers?

A. The Company has developed several 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. What are the use cases for digital tools and AI?

A. **Storm Declarations:** The Company already has clear standards for when a storm should be declared based on system conditions and resource availability. The opportunity for this use case is to build a prototype learning model that continuously optimizes when storm activations occur. Many storm declarations are clear decisions when a major event occurs. However, this use case will specifically help with the "borderline" decisions on blue sky and gray sky days.

Resource Planning: The Company believes that AI can assist 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 pre-staging for events. The target is for the resource plan to match the event size, thereby creating savings for customers by ensuring the most efficient resource planning.

Resource Utilization or Crew Movements: The Planning and Operations branches of the ICS teams need to make critically immutable and important decisions at the onset of an event. Consumers Energy's initial response to an event is one of the largest indicators of success. In large and catastrophic storms, where many headquarters have significant resource needs and a limited resource pool, it's imperative the ICS teams quickly assess the needs of 30 electric headquarters and allocate the available resources in the most efficient manner. The allocation must consider the location of the resources in proximity to the damage, the qualifications of the resources, knowledge of the system, and regional complexity factors (vegetation density, snow cover, road infrastructure, voltage differences) as these all affect the speed of restoration. For example, due to customer density and geographic complexities, Grand Rapids recovers faster than West Branch given the near-term weather forecast. Thus, it is critical not to move resources out of an area with an imminent weather threat.

Consider a reality-based scenario with 400 pre-staged line crews, 200 available forestry crews, 200 available wire-down resources, all in various locations around the state, that need to be immediately allocated to 15 storm-affected headquarters. Statistically, there are a near infinite number of solutions, but only **one** of those solutions is the most efficient. The faster the "one" most efficient solution is identified, and crews are mobilized, the more customers benefit in terms of duration and ultimately cost.

The gravity of this use case is to optimize that decision-making so decisions are made faster and result in more efficient outcomes.

Asset Identification: In 2024, the Company developed an asset identification AI model that learned what problematic insulators on the 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. 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, for example. An AI application could improve public safety and response efficiency by routing resources faster to where they are most needed.

Q. Would the Company deliver on all the above AI use cases if granted the requested investment?

A. All these AI use cases would contribute to the Company's service restoration processes as forward-thinking, industry-leading tools. The capital investment needed to fund research and development of the outlined use cases is small compared to the potential benefits. The Company plans to prioritize these use cases in the order in which they are listed above. The Company would begin with the Storm Declaration use case because the model has fewer variables and would quickly move next to the resource planning and crew utilization opportunities. The Company estimates an annual opportunity of reducing each medium-to-catastrophic event by 4 hours, with an estimated savings of $4.5 million annually with the realization of all use cases.

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 Pamela L. Bolden, and the insulator identification project I have discussed.

VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY OUTAGE CAUSES

Q. How does the Company currently identify and classify outage causes on its system?

A. When restoring power and responding to outages, the Company's field employees diagnose the outage causes and classify them using the Institute of Electrical and Electronics Engineers' (IEEE) standard outage cause codes, including the following: animals, equipment, trees, unknown, and weather. While the Company utilizes the IEEE standard, it recognizes there are opportunities to improve by relying less on "weather" and "unknown" cause codes. More accurate outage cause code reporting will help the Company as it analyzes its restoration performance and yield better data quality as it prepares its next reliability roadmap.

Q. In its distribution audit report, what did Liberty conclude about how Consumers Energy identifies and classifies outage causes?

A. On page 84 of Part I of Liberty's Report, it observed that the "weather" cause code "masks the actual cause of outages like trees, lightning, or ice . . . ." Similarly, it said that the "unknown" cause code is not precise but nonetheless "accounts for 11 percent of total interruptions." Ultimately, on page 17 of Part II of Liberty's Report, it concluded that

"weather" and "unknown" cause codes "diminish[ ] the effective[ness] of the analysis of outage causes necessary to identify and optimize solutions to address them."

Q. Did the Company respond to these findings in its comments and reply comments in the distribution audit docket?

A. Yes, the Company agreed that there is value in reducing the use of "weather" and "unknown" cause codes and discussed the initiatives then underway to improve how it identifies and classifies outages. Among other things, the Company said that it planned to benchmark its performance against peer utilities and identify measures being taken in the industry to categorize outages. Further, to better comply with IEEE standards, the Company said it was making changes to training, controls, and other operational processes. For example, the Company revealed its plan to establish new quality assurance and quality control processes to monitor and improve how line crews, dispatchers, and other storm responders categorize outages in real time when responding to incidents.

Q. Do you have any updates on the Company's progress?

A. Yes, the Company has engaged a third-party consultant to conduct the benchmarking that the Company described in its comments; this benchmarking is in-progress as of May 2025 and on-track to be completed before end of 2nd Quarter. The Company plans to complete process changes, including new quality assurance and quality control processes, by the end of the year. More accurate outage data will help the Company better plan its resources to restore power after outages while also enabling better planning for its Reliability Roadmap.

VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

Q. Is the Company following through with its plan to consolidate dispatch operations?

A. Yes. The Company is transitioning to consolidate operations.

Q. Have there been any adjustments to the plan?

A. Yes. The Company has been diligent in using the Plan-Do-Check-Act methodology with this project and has made enhancements to strengthen operational capabilities as a result. During the execution phase, it was identified through employee feedback that there was a risk of losing talent and that operational capabilities would be enhanced by staffing the back-up location, rather than maintaining an unstaffed back-up location. While the decision to staff the back-up location provides a better level of service and equitable cost avoidance, and SAIDI savings, it has changed the scope of the project.

Q. How are the operational capabilities enhanced by a staffed location that can serve as a back-up?

A. A staffed back-up location significantly boosts operational capabilities by providing a reliable contingency plan in case of disruptions at the other site. This set-up ensures continuity of operations by minimizing downtime and maintaining productivity to optimize safe and timely restoration for customers. The presence of trained personnel at each location allows for immediate response to emergencies, reducing the risk of operational delays. Additionally, it offers flexibility in resource allocation, enabling the company to adapt quickly to changing circumstances and maintain service levels. Overall, two fully staffed locations strengthen the Company's resilience and operational efficiency. Various companies have consolidated their control rooms into two manned centers for quick back-up. Independent research organizations have evaluated these strategies, highlighting benefits such as operational continuity, enhanced reliability, quick response, disaster recovery, and improved security.

Q. Please explain how staffing a back-up center increases operational capacity.

A. Foundationally, the Company cannot operate without redundancy and must maintain a back-up facility, which has always been part of its plan. Several intuitive benefits are realized by staffing the back-up facility.

- **Seamless Transition**: No recovery time required for the loss of critical systems at either facility, resulting in the seamless transition of operations without impacting customers.

- **Human Resource Diversity**: Consolidating all operations into one geographic location in the state requires a deep talent pool in one area. Sharing the staffing needs between two facilities, in different locations, enables a more diverse and deeper talent pool.

- **Operational Capabilities**: In emergency situations, the Company's dispatch centers can partially support each other, thereby enhancing operational efficiency to a limited extent. For instance, in early 2024, an emergency required the evacuation of one dispatch center. The remaining center was able to assume critical statewide dispatch responsibilities, maintaining some continuity in service restoration efforts, and mitigating prolonged customer outages. Similarly, during the severe weather event on April 2, 2025, tornado warnings led to the evacuation of one dispatch center. Within five minutes, the alternate center resumed ongoing storm restoration activities, preventing delays in service restoration for the Company's customers. These instances highlight the current back-up capabilities between the Company's dispatch centers. The ability to back up non-dispatch functions, typically associated with monitoring and controlling the electric grid at higher voltages, will be fully realized upon the final control center consolidation.

Q. Can you talk about the benefits that have already been realized from the work that has been completed and detail the changes from previous cases?

A. Customers have already benefited from $3.4 million of avoided costs and a 4.1-minute SAIDI reduction achieved during the transition and throughout 2024. Testimony in Case Nos. U-21389 and U-21585 anticipated these avoided costs and SAIDI reductions, as Company witnesses outlined the overall significant cost savings and SAIDI improvements. Initially, the Company planned to establish one fully staffed control center and one unstaffed back-up facility, which was expected to yield annual savings of $8.6 million and

reduce SAIDI by 15 minutes. The total project cost was estimated at $17.2 million, with a schedule spanning from 2023 to 2026.

The current filing proposes creating two fully staffed control centers, each capable of functioning as a back-up for the other. This change is expected to yield annual savings of $10.2 million and reduce SAIDI by 20.8 minutes. The total project cost is now estimated at $30.6 million, with a schedule spanning from 2023 to the first quarter of 2027. Additional information on the revised benefits can be found later in my testimony.

Q. What milestones of this consolidation project have been completed as of the end of 2024?

A. Milestones for this project can be grouped in three areas: Building & Facilities, Process Efficiencies, and Resource Preparedness.

- Building & Facilities:
  - Consolidated three dispatch centers into two, strategically located in Jackson and Grand Rapids.
  - Initiated asbestos removal and remediation efforts.
  - Developed conceptual plans and cost estimates.
  - Currently in the preparation phase for design and engineering.
- Process Efficiencies:
  - Expanded Jackson's operating hours from 16 hours a day, five days a week, to 24 hours a day, seven days a week.
- Resource Preparedness:
  - Merged three operating groups into two: High Voltage Distribution and Low Voltage Distribution, ensuring alignment with transitional roles.
  - Operational responsibilities were adjusted to enhance efficiency and ensure a smoother workflow. This approach helped maintain productivity and adapt to new processes more effectively. By redistributing tasks and roles, the team was able to minimize disruptions and optimize overall performance during the transition phase.

Q. Have any benefits been realized in 2024 because of the Control/Dispatch Center Consolidation project?

A. Yes, from January 1, 2024, to December 31, 2024, the Company achieved measurable benefits, including:

- Cost Savings: Avoided $2.483 million in service restoration costs.
- Cost Savings: Reduced $0.9 million in Grid Operations Labor costs.
- Improved Reliability: Reduced all-weather SAIDI by 4.1 minutes due to:
  - Shortened storm durations through enhanced storm readiness.
  - Fewer activations of ICS responders.

Following the 2023 consolidation of three Dispatch Control Centers into two, the Company adjusted operational boundaries, enabling both control centers to be fully engaged in storm restoration efforts from the onset of an event. This strategic change enhanced resource allocation, optimized service restoration, and lowered operational costs. The implementation of 24/7 operations at one dispatch center in 2024, coupled with continuous improvement initiatives, allowed the Company to leverage an expanded management span of control and boost productivity during service restoration.

The operational efficiencies implemented enabled the two remaining Control/Dispatch Centers to manage restoration efforts for larger-scale events more effectively than before consolidation. As a result, the need for ICS responder activations has decreased, further optimizing response efforts. Establishing two fully staffed facilities is essential to ensure redundancy, enhance resilience, and maximize the benefits of improved resource allocation and operational efficiency.

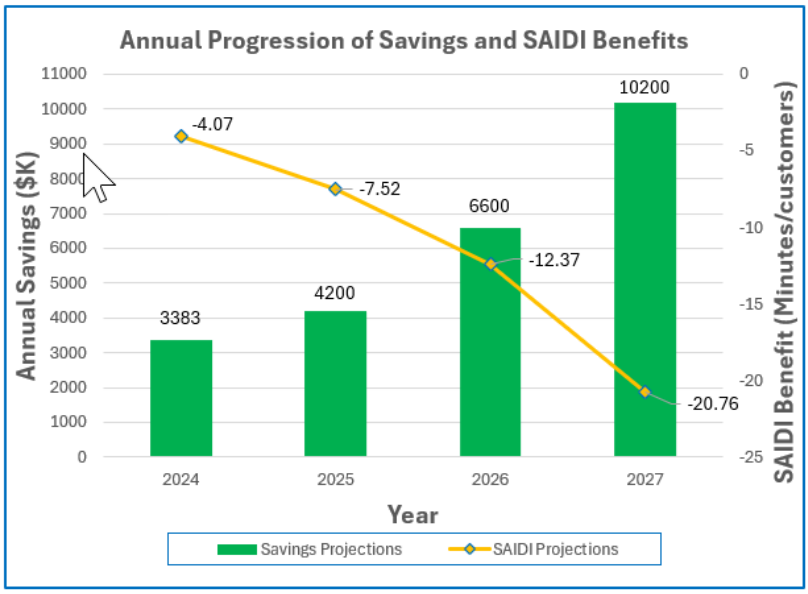
Q. What are the projected total cost savings and SAIDI improvements associated with this project?

A. Full benefit realization is projected by March 2028, one year following project completion. By this time, the Company expects to achieve:

- A sustainable reduction in all-weather SAIDI of 20.8 customer-minutes; and
- Annual cost savings of $10.2 million through avoided operational expenses.

Figure 7 illustrates the ramp-up of these benefits, including those already realized in 2024.

Figure 7
Control/Dispatch Center Consolidation Project Annual Progression of Benefits



Q. Were there any adjustments to the original benefits filed in Case Nos. U-21389 and U-21585?

A. Yes, there were adjustments to the original benefits filed in Case Nos. U-21389 and U-21585. The initial projections for the Control/Dispatch Center consolidation project have been refined based on historical data from 2022–2023 and the realized benefits in the

historical test year 2024. These adjustments were necessary to provide a more accurate and realistic estimate of the project's impact on service restoration and outage duration.

Figure 8 summarizes the projected cost savings and all-weather SAIDI benefits, with column (c) reflecting revised figures and column (a) displaying the original projections.

Figure 8
Control/Dispatch Center Consolidation Project Benefits

Line No.		(a)	(b)	(c)
		Original Benefits	**Adjustment**	**Revised Benefits**
1	Service Restoration Cost Reduction	$7.6M	$2.5M	$10.1M
2	Grid Operating Labor savings	$0.9M	Realized in 2024	$0M
3	Facilities / IT / expenses	$0.1M	No Change	$0.1M
4	**Total Cost Savings**	**$8.6M**	**$2.5M**	**$10.2M**
5				
6	**SAIDI Reduction**	**15 minutes**	**5.8 minutes**	**20.8 minutes**

Q. Please explain the adjustments in the "Service Restoration Cost Reduction" category.

A. The initial estimate assumed a two-hour improvement in restoration time for both gray sky and catastrophic conditions. However, after reviewing historical data from 2022–2023, and analyzing realized benefits in the historical test year 2024, future projections have been refined to reflect a two-hour improvement for gray sky conditions and a 24-hour improvement for catastrophic conditions.

These adjustments are driven by increased use of technology, and additional operational efficiencies that have been identified, enabling faster and more effective power restoration. Key factors contributing to these efficiencies include clearer role alignment,

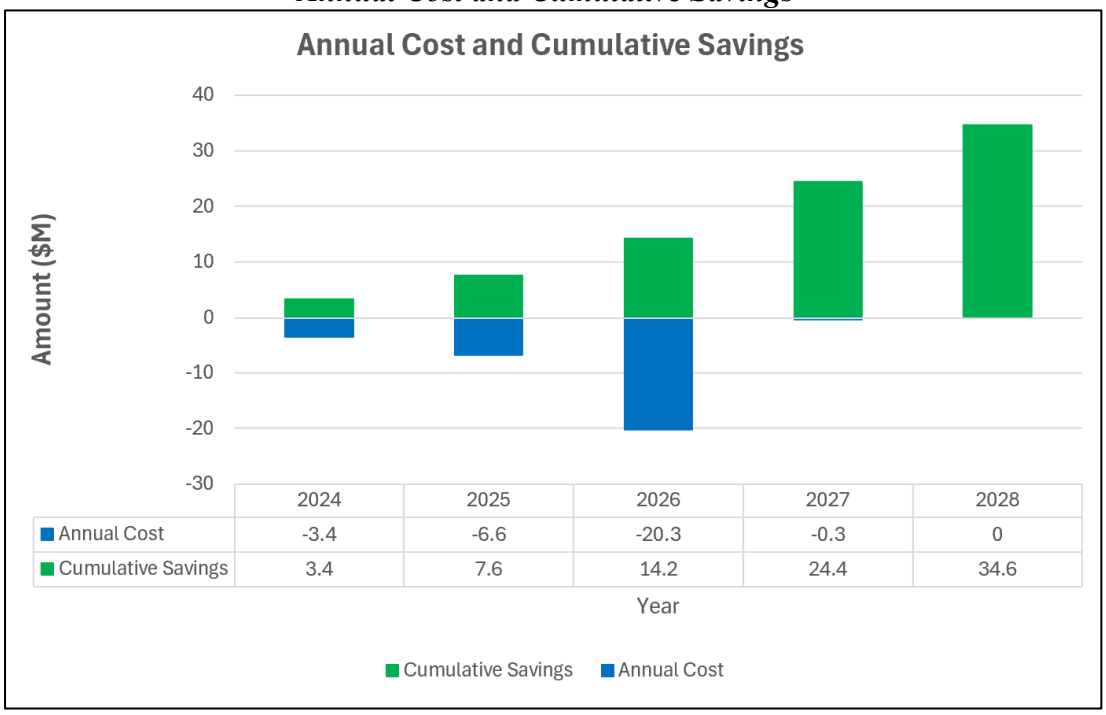
reduced operational hand-offs, co-locating operating groups within the same control center, enhanced training for Grid Operators, and improved system-wide situational awareness.

Q. What are the projected costs associated with this project?

A. The Company projects a total expenditure of $30.7 million for this project, including $15.8 million in the test year ($15.5 million in capital and $308,000 in O&M). These costs support the completion of construction, commissioning, and occupancy of the operating control centers by early 2027, as well as the integration of support group operations within the consolidated control centers.

The capital costs for this project are detailed in Company witness Quentin A. Guinn's Exhibit A-102 (QAG-3), page 1, lines 25 and 26, along with the associated testimony. The O&M costs are provided in Company witness Kelly's Exhibit A-128 (MPK-18), line 27, and the corresponding testimony. Figure 9 illustrates the annual costs, and cumulative savings for the project.

Figure 9
Control/Dispatch Center Consolidation Project Financial Overview: Annual Cost and Cumulative Savings



The costs and benefits figures for this consolidation project represent a shift from testimony provided in previous rate cases as explained earlier in my testimony.

Q. During the historical year, how much was spent on the Control/Dispatch Center Consolidation project?

A. From January 2024 through December 2024, the Company incurred $3.4 million in costs for the Control/Dispatch Center Consolidation project. These expenditures covered design services, material acquisition, and initial space renovations.

Q. Please summarize the Company's proposal for Control/Dispatch Center consolidation and its benefits for customers.

A. The Company's proposal involves consolidating the System Control, Distribution Control, and Dispatch Centers into two fully staffed control centers—one in Jackson and one in

Grand Rapids. Each center will serve as a back-up for the other, with associated process and organizational changes delivering significant customer benefits.

Key Benefits:

- Annual Cost Savings:
  - Service restoration annual cost reduction: $10.1 million.
  - Facilities/IT/Training expense annual savings: $0.1 million.
  - Total annual savings: $10.2 million.
  - A one-time Grid operating labor savings: $0.9 million.
- Outage Response Benefit:
  - All-weather SAIDI reduction: 20.8 minutes per customer.
- Project Cost and Implementation:
  - Total cost: $30.7 million ($15.8 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 support group operations.
- Initial Impact:
  - 2024 results: $3.383 million in cost savings and a 4.1-minute SAIDI reduction per customer due to process, organizational, labor reduction, and employee skilling improvements.
  - Full benefit realization projected by March 2028.

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-21870

REVISED DIRECT TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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 Senior Manager of Forestry Operations.

Q. Please describe your educational background and work experience.

A. I have 11 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 Senior Manager 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 ever been a witness in a Michigan Public Service Commission ("MPSC" or the "Commission") case?

A. No, but I have supported Pamela L. Bolden and Chris A. Shellberg as they prepared testimony and exhibits in the last several rate cases: Case Nos. U-21585, U-21389, U-21224, U-20963, and U-20697. Besides this, I 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 support the Company's request in this case for an increase in funding for its Line Clearing Program. My direct testimony is presented in six sections: 1) Description of the Line Clearing Program; 2) Recent Progress of the Line Clearing Program; 3) Vision for the Line Clearing Program; 4) Reliability Benefits of the Line Clearing Program; 5) Expense Requirements for the Line Clearing Program Vision; and 6) Resourcing Plan for the Line Clearing Program Vision.

EXHIBITS

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-170 (SES-1)	Line Clearing O&M Expense;
Exhibit A-171 (SES-2)	Projected LVD Tree-Caused Reliability Impacts of the Line Clearing Ramp-Up Plan;
Exhibit A-172 (SES-3)	2025 HVD Line Clearing Work Plan;

Exhibit A-173 (SES-4)	2025 LVD Line Clearing Work Plan;
Confidential Exhibit A-174 (SES-5)	Post-Work Review Supporting Documentation Examples;
Exhibit A-175 (SES-6)	Summary of O&M Expenses Projected Using Inflation;
Exhibit A-176 (SES-7)	Formal Optimization Analysis of Line Clearing Cycles; and
Exhibit A-177 (SES-8)	Utility Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities and Operations.

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 four subprograms: (i) maintenance clearing; (ii) brushing and herbicide treatment; (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local ordinances). HVD Line Clearing also includes Forestry Operations Administration expenditures.

The IVM program provides reliability benefit 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 will eventually fall onto the line. These situations require immediate remediation to prevent an outage.

Q. What is HVD noxious weed control?

A. 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.

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) brush control. 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 a reliability benefit for all customers connected to the circuit. First zones are selected based on the previous 12-month tree-related outage history each fall when work plans are developed for the upcoming year. Clearing of first zones is targeted for first and second quarters of the work plan year to maximize the reliability benefit to all customers of the circuit. First zones are currently cleared to the same specifications as program maintenance with the exception that individual trees with overhanging branches regardless of clearance above conductors have been considered for 100% removal of these overhanging branches.

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 2024 calendar year, the Company cleared 42 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 brush control?

A. LVD brush control 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-174 (SES-5) contains documentation supporting this process. As an example, for scheduled O&M work, the Company required 720 hours of non-billable labor in 2024 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 Andrew R. Snider 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 for its HVD Line Clearing subprogram.

A. The Company has continued to maintain a four-year clearing cycle for its HVD system. Figure 1 below shows five-year actual clearing and expenditure data 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 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	4-Year Cycle 2021-2024
Cleared Miles	1,116	1,178	1,106	1,153	1,203	4,640
Planned Miles	1,103	1,129	1,161	1,164	1,166	4,620
O&M Expense ($M)	$9.17	$10.74	$10.99	$11.30	$10.73	$43.76
Planned O&M Expense ($M)	$9.48	$12.60	$11.71	$12.06	$12.28	$48.65
$/line mile	$8,219	$9,117	$9,932	$9,801	$8,919	$9,431
Clearing Cycle (years)	4.2	4.2	4.2	4.2	4.0	4.0

Q. Please list any prioritized projects for maintenance clearing work in the HVD line clearing subprogram for 2025.

A. In 2025, the Company is planning HVD line clearing on the lines listed in Exhibit A-172 (SES-3).

Q. Please describe the Company's recent progress for its LVD Line Clearing subprogram.

A. The Company has been working towards attaining a seven-year effective clearing cycle for its LVD system and has not yet attained this cycle. Figure 2 below shows five-year actual clearing miles, expenditure data, workplan backlog and cycle percentages, and a

summarization of the most recent five years of clearing towards the seven-year effective cycle target.

FIGURE 2
LVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	5-Year Actual 2020-2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030	28,273
O&M Planned Miles	3,166	5,223	5,636	5,875	6,760	26,660
O&M Expense ($M)	$46.10	$75.83	$91.02	$97.79	$99.49	$410.23
Planned O&M Expense ($M)	$41.36	$71.43	$81.49	$87.97	$105.37	$387.62
$/line mile	$10,948	$14,364	$14,248	$15,364	$16,499	$14,510
Effective Clearing Cycle (years)	13.1	10.6	9.1	9.3 ~~2~~	9.7	10.2 ~~1~~
Workplan Backlog Miles Percentage	98%	87%	67%	82%	80%	82%
Workplan Cycle Miles Percentage	2%	13%	33%	18%	20%	18%

Q. Please list any prioritized projects for full circuit clearing work in the LVD line clearing subprogram for 2025.

A. Exhibit A-173 (SES-4) shows the 2025 LVD work plan which includes the forestry model output circuits and circuits begun in 2024 with completion carrying over to 2025.

Q. Please describe the seven-year effective cycle and how it works.

A. The seven-year effective cycle describes a 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. Upon achieving the seven-year effective cycle, 14.4/24.9 kV circuits would be cleared on average between four to six years, 7.2/12.47 kV circuits would be cleared on average between six to eight years, and 4.8/8.32 kV circuits would be cleared on average between eight to ten years depending on the circuits' historical performance, reliability predictions from the forestry model, and safety considerations. The Company first used historic 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 it is 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.

Q. What recent technology enhancements has the Company utilized in its Line Clearing Program?

A. The Company recently 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 has been 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 workplan to capture the most reliability and safety benefit for annual spend. The output of the forestry model is an input into the forestry workplan selection tool. This new

technology was first utilized to generate the 2023 LVD full circuit clearing workplan 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 benefit for the spend, this selection tool includes the use of satellite imagery analysis to more accurately project costs to clear them. 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.

VISION FOR THE LINE CLEARING PROGRAM

Q. What is the Company's vision for its Line Clearing Program?

A. The Company's vision 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 proposing to maintain a four-year clearing cycle for its HVD system and, for its LVD system, proposing a ramp-up to a five-year clearing cycle and performing more aggressive line clearing on targeted three phase primary lines. The

proposed timeline to achieve the shortened line clearing cycle and scope of more aggressive line clearing is targeted by the end of the 2030-2031 test period, which is a similar timeline the Company proposed in MPSC Case No. U-21585 to achieve its previous seven-year effective cycle strategy. Additionally, the Company is proposing 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 proposal includes a ramp-up strategy 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 proposes to 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 in 2031. At that time, the Company will reevaluate other tactics for continuous improvement in risk management.

Q. Is the Company making changes to its key tracking metrics for LVD line clearing?

A. Yes. As noted, the Company's vision includes bringing all LVD circuits, regardless of voltage class, to a state of having been fully cleared within a five-year period to establish a consistent, full cycle. In its previous rate cases describing the seven-year effective cycle strategy, the Company has tracked progress towards the cycle utilizing a total-miles metric

that encompassed all LVD full circuit clearing miles, LVD subprogram clearing miles, LVD spray miles, and LVD capital clearing miles. This metric was used to summarize the effective cycle for a given year, as shown in Exhibit A-170 (SES-1), line 40. To support its vision, the Company will now track LVD full circuit clearing miles as its main metric towards attaining the five-year cycle line clearing strategy and track other miles (LVD subprogram clearing miles, LVD spray miles, and LVD capital clearing miles) separately and not as part of the standard cycle. This metric is shown in Exhibit A-170 (SES-1), line 23. This ensures the entire LVD system is brought to a consistent state of clearing 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. Starting in 2026 and 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.[1]

[1] Specifically, Alliant Energy, Ameren Missouri, American Electric Power perform mid-cycle clearing.

Q. How will the Company address the backlog of circuits not cleared in many years?

A. The Company's proposal to execute a five-year cycle strategy 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 this test period. 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 workplan for the year to be kept on-cycle. As outlined in Figure 4, remaining miles for the workplan will be backlog miles, addressed throughout the ramp-up strategy timeframe of this test period (Year 1) through the 2030-2031 test period (Year 5).

FIGURE 4
PLAN FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Vision Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	9,019	5,279	3,740	26,684
Year 2	10,885	6,338	4,547	22,138
Year 3	12,814	6,365	6,449	15,689
Year 4	13,588	6,042	7,546	8,143
Year 5	14,837	6,694	8,143	0

Q. Why is the Company deviating 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 acknowledged the reliability benefits of shorter cycles (i.e., a reduced cycle results in lower tree-caused outage rates on the LVD system), it has sought to balance reliability benefits with costs to maintain the cycle. In previous rate case analysis, a seven-year effective cycle was outlined as the most cost-beneficial approach for customers. Since that analysis took

place, additional data analysis and information, including Liberty's recommendation and report, has become available for consideration. The Company has carefully evaluated projected costs and benefits of a shorter line clearing cycle for its LVD circuits and has determined that a five-year line clearing cycle is the right approach to significantly improve electric reliability while responsibly managing customer bill impacts.

Q. Why is the Company's vision timeline to achieve the cycle longer than Liberty's recommended timeline?

A. While the Company is proposing a line clearing cycle that aligns with Liberty's recommendation, the aggressive timeline of achieving the shorter cycle by year-end 2028 is not operationally feasible due to rate case timelines and resource acquisition challenges that would result from such a short timeline (e.g., a full ramp-up and execution from mid-2026 through year-end 2028). These resource acquisition challenges could also lead to higher costs if the Company is required to rely on additional out-of-state crews, and these higher costs also caution against a too-aggressive timeline. The Company's proposal to achieve the reduced line clearing cycle reflects an operationally feasible timeline that is just two to three years longer than Liberty's recommendation: by the end of the 2030-2031 test period.

Q. Has the Company performed a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing, including an evaluation of shorter clearing cycles?

A. Yes. To comply with the Order for MPSC Case No. U-21389, the Company filed its formal optimization analysis of line clearing cycles on September 3, 2024, in Case No. U-20697 (the "Analysis"). The Analysis is included in Exhibit A-176 (SES-7).

Q. What was the conclusion of the Analysis?

A. The conclusion of the Analysis was an optimal cycle length between six and seven years, prioritizing and focusing on residential customers. A four-year cycle length was first identified as an optimal cycle when considering combined costs across all customer types (residential and non-residential). The Company took the analysis a step further, considering how line clearing and service restoration costs would be allocated to each customer type. Residential customers bear the majority of the line clearing and service restoration costs through rates as they make up the majority of the electric customers served (about 88% of total). Upon isolating cost impacts on residential customers, and utilizing then-current data, the Company's refined analysis found that a longer cycle length between six and seven years was the optimal point for residential customers minimizing total costs.

Q. Why isn't the Company proposing a cycle length matching the conclusion of the Analysis for residential customers?

A. The Company acknowledges Staff's concerns regarding the approach taken with the Analysis. Among these, Staff comments that the Analysis uses the Interruption Cost Estimate ("ICE") calculator and that these costs are low.[2] While the Company utilized the data from the ICE calculator as it is the best available data of its kind, it acknowledges that a higher residential customer cost of outages would drive the Analysis conclusion towards a shorter optimal cycle for residential customers. The Company is adjusting its proposed line clearing cycle length to accommodate Staff's concern, among other reasons. The shorter cycle length also aligns with Liberty's recommendation, which is influenced by

[2] Michigan Public Service Commission Staff Reply Comments on the Final Report Utility Distribution Audit of Consumers Energy, January 17, 2025, pages 2-3

benchmarking of other utilities, and would result in lower tree-caused outage rates on the LVD system to provide customers with better reliability.

Q. Has the Company analyzed the feasibility of more aggressive line clearing in everything outside of the first zone?

A Yes. To comply with the Order for MPSC Case No. U-21389, the Company has analyzed the feasibility of more aggressive line clearing, defined as canopy removal, in everything outside of the first zone and alternate options in Case No. U-21585.

Q. For the Company's vision, 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. In comparison, the Company's general line clearing specification for LVD primary has allowed 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 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 small canopy removal study on approximately 42 miles of three phase primary which resulted in an observed average contractor cost increase of 35% per mile cleared. Figures 5 and 6 show examples of canopy removal on an urban and rural section of circuit respectively, pre- and post-clearing in 2022.

FIGURE 5
CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2022

FIGURE 6
CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2022

Q. Where is the Company proposing to remove canopy on its LVD system?

A. The Company is proposing canopy removal on 10% or roughly 5,500 miles of overhead primary, targeting the three phase portions of circuits that have the highest consequence of failure due to serving the most downstream and/or critical customers. Decreasing the risk of tree-caused outages along this targeted three phase primary increases the availability and enablement of manual and automatic switching capabilities, reducing the impact of outages that may occur regardless of cause.

Q. Does this scope of canopy removal match an option presented in Case No. U-21585's feasibility of more aggressive line clearing?

A. No, this proposal does not directly match an option presented in Case No. U-21585, where zones and number of phases were used to differentiate between options. The Company is proposing that zone number alone not be the determining factor for canopy removal, but the consequence of failure of the section of line in question, which will inherently include the first and some second zones, but may extend past the second zone depending on the zone attributes (e.g., number of customers served downstream, and/or if the conductor is within the path of substation-to-substation connection to enable switching opportunities).

Q. Why is the Company proposing to remove canopy on targeted LVD three phase lines?

A. Upon evaluation of the feasibility of more aggressive line clearing on its LVD system, the Company has integrated this tactic into its vision, scoped to the sections of line that are projected to provide the greatest impact to overall customer reliability for the incremental expense. It is not uncommon for electric utilities to have more aggressive clearing specifications in early zones versus later zones; inherently, more customers are served by early zones and by fewer zone miles, which increases overall customer benefit of more

aggressive line clearing in these zones. As outlined in Case No. U-21585, 100% of customers fed by LVD lines are served within and downstream of first zones, which comprise about 6% of total LVD miles.

Q. How will the Company measure the reliability impact of the proposed targeted canopy removal?

A. To measure the reliability impact of the proposed targeted canopy removal, the Company plans to compare the zones that had canopy removal (i.e., "treatment population") to zones or circuits that 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 is considering including 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 is proposing to begin executing on its canopy removal strategy in this test period, it is crucial that the data size 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 impact of the proposed targeted canopy removal would appear at the earliest in the 2028 Line Clearing Program Annual Report, analyzing 2027 reliability performance. This will allow the treatment population time to begin collecting reliability data.

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 is to occur 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 the outage (i.e., dispatcher). The Company plans on utilizing 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 will be targeted for the outage review program?

A. The Company is proposing an outage review trigger upon meeting 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.

Q. What line clearing tactics are the Company proposing for wildfire mitigation?

A. In Case No. U-21585, the Company proposed to implement a five-year line clearing cycle in elevated wildfire risk areas better to manage growth and limit potential vegetation to conductor contact. The incremental expense for this was outlined in Company witness Michael P. Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585. Because the Company is proposing a shorter five-year cycle for the entirety of its LVD system, the line clearing expense in the elevated wildfire risk areas is now included in the overall Line Clearing Program costs outlined in Exhibit A-170 (SES-1) and are no longer an incremental expense.

While the Company outlines a timeline to achieve the vision by the end of the 2030-2031 test period for all LVD circuits, it is proposing a more aggressive timeline in wildfire

risk areas, namely, achieving the five-year cycle for circuits in the relatively high wildfire risk area by year-end 2026 and relatively moderate wildfire risk area by year-end 2028.

Q. What does the Company have planned for future enhancements to technology?

A. The Company continues to evaluate new forestry workflow management processes and technology enhancements. 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 exploring an opportunity to upgrade 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 pursuing advanced remote sensing to improve its forestry model?

A. No, the Company is not pursuing system-wide advanced remote sensing to improve its forestry model at this time. The Company is conducting a small pilot to capture Light Detection and Ranging ("LiDAR") imagery, which was proposed in Case No. U-21585. The purpose of this pilot is to inform and support the execution strategy of LVD line clearing tactics in relatively high-risk wildfire areas. The Company is proposing to continue this pilot annually to evaluate the benefits of utilizing this data on a small scale first, before re-evaluating expanding this LiDAR pilot to a larger scope, up to and including LVD system-wide utilization. This supports the Company's phased approach to imagery analysis utilization: short-to-medium-term utilization of zero-to-low-cost satellite imagery analysis and focused LiDAR pilot projects during the ramp-up to a five-year cycle, and

long-term re-evaluation of larger scope LiDAR acquisition and utilization to further reduce outages once the LVD system is fully on the five-year cycle.

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 7 below shows the history of tree-caused interruptions affecting customers from 2020 through 2024 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 proposed five-year cycle strategy will yield significant improvement to customers' electric service.

FIGURE 7
TREE-CAUSED RELIABILITY METRICS 2020 THROUGH 2024
ALL VOLTAGES INCLUDING MEDS (Excluding ITC incidents)

Description	2020	2021	2022	2023	2024
Incidents	18,599	24,163	17,078	18,298	20,326
Customers Interrupted	930,974	1,314,220	919,156	1,037,857	1,084,052
Customer Minutes (M)	494.290	1011.992	444.309	899.756	548.880

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 the HVD line clearing subprogram?

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 2020 through 2024, 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 471 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 the LVD line clearing subprogram?

A. The Company's vision 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-171 (SES-2) illustrates the projected reduction in non-MED and MED tree-caused primary outage incidents, System Average Interruption Frequency Duration ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). Figures 8, 9, and 10 below show the reliability projections by metric for 2025 through 2030 for the proposed line clearing spending levels to achieve the Company's vision. The values at the top of each bar represent overall reliability projections including MED.

FIGURE 8
PROJECTED 2025-2030 LVD TREE-CAUSED PRIMARY OUTAGE INCIDENTS

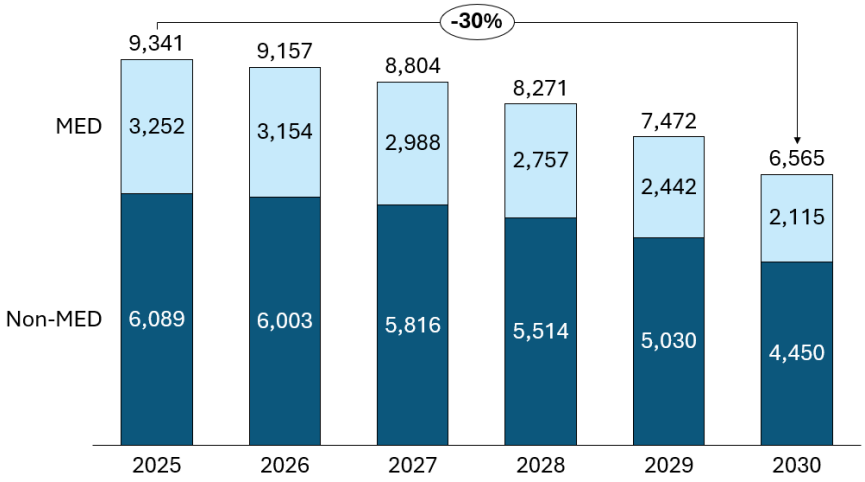


FIGURE 9
PROJECTED 2025-2030 LVD TREE-CAUSED SAIFI DUE TO PRIMARY OUTAGES

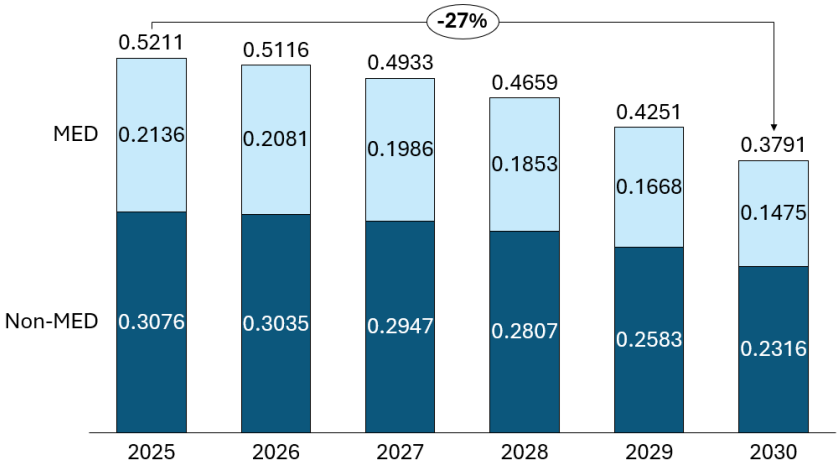
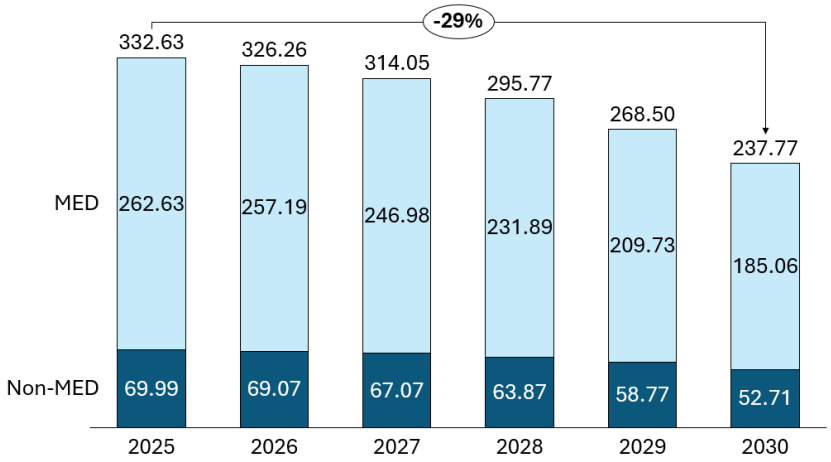


FIGURE 10
PROJECTED 2025-2030 LVD TREE-CAUSED SAIDI DUE TO PRIMARY OUTAGES



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-171 (SES-2) are from the Company's reliability model as described in Company witness Kelly's testimony, page 28, lines 1 through 10. The reliability projections in Exhibit A-171 (SES-2) also factor in the Company's proposed canopy removal 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,[3] 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. My Land Plan, provided by the American Forest Foundation, describes wind firmness 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.[4] 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

[3] 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. . . .")
[4] American Forest Foundation, *How Windstorms Affect Your Forest*, My Land Plan, https://mylandplan.org/content/how-windstorms-affect-your-forest.

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,[5] 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 plans to utilize the proposed 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.

Q. Has the Company considered the benefits of shifting to a four-year fixed line clearing cycle based on the findings of the Analysis as the Commission directed in its recent Order in Case No. U-21585?

A. Yes, the Company has considered the costs and benefits of shifting to a four-year fixed line clearing cycle, and it asserts that the prudent next step in the evolution of its Line Clearing Program is the outlined five-year line clearing cycle, continuing to prioritize residential customer cost-benefit. The Company has compared the estimated costs and projected benefits of achieving a four- and five-year line clearing cycle in the same ramp-up strategy period of this test period through the 2030-2031 test period. The Company estimates that achieving a four-year cycle in the same timeframe could raise expenses nearly 15% overall, with some years as high as 23%. In its comparison, the Company assumed a 0% change in expenses in this test period as it has projected the most aggressive crew resourcing plan

[5] 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/

it believes it can achieve in the first year. The Company estimates that this increased spending could result in only 3% additional reliability benefit across multiple metric types due to diminishing returns.

It is important to note that, to increase line clearing miles in this ramp-up timeframe, the majority of the incremental expense is due to increasing out-of-state tree crewing. This resource is a more expensive resource than local tree crewing. Once the Company is on a 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; however, the Company's LVD system is not currently on a five-year cycle, and significant out-of-state resources would be necessary to bring the system to an even shorter four-year cycle at this time. Once the five-year cycle is attained, the Company will reevaluate other tactics for continuous improvement in risk management, including cycle considerations.

Q. What reliability benefit is attributed to canopy removal?

A. The Company estimates it would see a 4% reduction in primary tree-caused incidents from canopy removal on targeted three phase lines.

Q. How was the reliability benefit of canopy removal calculated?

A. The Company utilized benchmarking data found in Exhibit A-177 (SES-8)[6] indicating a 6% outage reduction opportunity through canopy removal. Because the Company is proposing to remove canopy along a portion of its LVD primary, and it estimates this portion of LVD primary impacts 2/3rds of customers impacted by tree-caused outages, it

[6] Page 27, Figure 6-4 (Permission to use this study was obtained from its authors).

applied this 6% reduction across roughly 2/3rds of customers interrupted by tree-caused events. This results in a calculation of a 4% tree-caused reliability improvement overall.

EXPENSE REQUIREMENTS FOR THE LINE CLEARING PROGRAM VISION

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 11 below:

FIGURE 11
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
2020	Actual	1,116	46	$9.17	$1.18	41
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	Projected	1,104	129	$12.20	$4.12	38
2026	Projected	1,177	138	$11.99	$4.49	38
2027	Projected	1,162	138	$11.55	$4.58	38
2028	Projected	1,120	138	$11.20	$4.66	38
2029	Projected	1,167	138	$11.40	$4.75	38
2030	Projected	1,177	138	$11.60	$4.83	38

Q. What are the projected expense requirements for the LVD system ramp-up to achieve the Line Clearing Program vision 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 Program vision are displayed in Figure 12 below:

FIGURE 12
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
2020	Actual	3,679	294	238	258	$46.10	$5.67	220	0	220
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 ~~244~~	443	169 ~~8~~	$97.79	$5.59	348	0	348
2024	Actual	5,400	209 ~~244~~	421	270 ~~258~~	$99.49	$9.69	347	0	347
2025	Projected	6,108	244	413	325	$113.20	$14.01	364	0	364
2026	Projected	7,891	199	405	325	$152.97	$14.29	403	53	456
2027	Projected	10,885	149	454	325	$201.75	$14.57	420	120	540
2028	Projected	12,814	137	501	325	$226.28	$14.87	420	158	578
2029	Projected	13,588	75	491	325	$230.43	$15.16	420	158	578
2030	Projected	14,837	75	508	325	$236.81	$15.47	420	158	578

Q. What expense is the Company projecting to maintain the five-year clearing cycle after it is achieved?

A. The Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period is $180.359 million ($168.525 million of which are LVD expenses) and subject to inflation in years after. The Company is referring to this measure as the baseline expense.

Q. What baseline expense requirement is the Company projecting for the test period?

A. The Company projects a baseline expense requirement of $164.446 million ($152.606 million of which are LVD expenses) for the test period.

Q How were the baseline expense requirement for the test period and the baseline expense for the years leading up to achieving the five-year cycle calculated?

A. The baseline expense requirement for the test period of $164.446 million was calculated utilizing the Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period, adjusted to test period dollars.

Figure 13 below shows the outcome of this calculation methodology for the calendar years leading up to achieving the five-year cycle.

FIGURE 13
PROJECTED LINE CLEARING PROGRAM EXPENSES AND BASELINE EXPENSE REQUIREMENTS

12-Month Timeframe	Total O&M Expense ($M)	Baseline O&M Expense ($M)
2026 Calendar	$164.953	$163.357
2027 Calendar	$213.300	$166.624
2028 Calendar	$237.485	$169.956
2029 Calendar	$241.826	$173.356
2030 Calendar	$248.414	$176.823
U-21870 Test Period	$186.684	$164.446
Post-Vision	$180.359	$180.359

Q. Why is this baseline expense requirement different than the five-year cycle estimation in the Analysis?

A. In the Analysis, the Company estimated an annual expense to maintain the LVD system on a five-year cycle in a steady state (once the cycle had already been achieved and there are no backlog miles that have gone longer than the cycle length between clearing) of $134.441 million.[7] This value is different than the LVD baseline expense requirement in Exhibit A-170 (SES-1), column (q), line 12, of $152.606 million. There are refined and updated assumptions that have impacted this projection, including overall crew resourcing, and the consideration of overtime for both local and out-of-state tree crews. Another notable difference in these values is that the Analysis utilized the timeframe of one year using costs inflated to 2024, whereas the baseline expense requirement in Exhibit A-170 (SES-1) is adjusted to the test period for this case.

[7] The Analysis, Attachment 3, column (g), line 42

Q. What level of spending is the Company proposing for the 2026 calendar year and the 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 $164.953 million for line clearing in the 2026 calendar year and $186.684 million for line clearing in the test period, as shown in Figure 14 below and in Exhibit A-170 (SES-1).

FIGURE 14
LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

Categories	2026 Calendar Total O&M Expenses	Test Period Total O&M Expenses
HVD Line Clearing	$10,910,683	$10,755,522
LVD Line Clearing	$144,782,420	$164,864,105
Line Clearing Admin	$9,260,324	$11,064,347
Total	**$164,953,427**	**$186,683,974**

Q. What is the line item in Figure 14 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 2026 calendar year is reflected in Exhibit A-170 (SES-1), column (j), lines 30, 31, and 32.

Q. What inflationary rates were used to determine the projections in Figure 14?

A. The Company's internal labor expenses for Forestry Operations shown in Figure 14 and Exhibit A-175 (SES-6) are a combination of current staffing, anticipated retirements, replacement and new hiring, merit increases, and contracted planning resources. Please

refer to the direct testimony of Company witness Patrick D. Daly, page 14, lines 9-11, and page 15, lines 1-2, 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 of a minimum of 0.0% per year up to a maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443. Figure 15 below shows the 2024 results for Producers Price Indices WPUFD4 and WPU443 published January 14, 2025.

FIGURE 15
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: 2019 to 2024

	Percent Change												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2019	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.4	1.7
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	2.6	3.0	3.3	2.3

PPI Commodity Data
12-Month Percent Change
Series Id: WPU443
Not Seasonally Adjusted
Series Title: PPI Commodity data for Rental and leasing of goods (partial)-Construction, mining, and forestry machinery
Group: Rental and leasing of goods (partial)
Item: Construction, mining, and forestry machinery and equipment rental and leasing
Base Date: 200903
Years: 2019 to 2024

	Percent Change												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Annual**
2019	-0.1	-1.4	-0.9	0.4	1.8	1.9	0.8	0.8	0.1	-0.5	-1.1	-1.3	0.0
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	0.6	0.0	0.1

Q. What is the Company's projected 2026 calendar year and test year spending level, for which it is requesting cost recovery, in the HVD line clearing subprogram?

A. The Company is projecting HVD line clearing expenses of $11.987 million in the 2026 calendar year and $11.840 million in the test period, as shown in Figure 16 below and in Exhibit A-170 (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 2026 calendar year and test period for each category as identified in Figure 16 below:

FIGURE 16
HVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

	2026 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Maintenance clearing	$4,886,488	587	$4,870,358	584
Brush control	$5,869,195	586	$5,730,163	584
Demand	$60,000	4	$60,000	4
Noxious weed control	$95,000	n/a	$95,000	n/a
Line Clearing Admin	$1,076,037	n/a	$1,084,138	n/a
Total	**$11,986,720**	**1,177**	**$11,839,660**	**1,172**

Q. What spending level for the HVD line clearing subprogram was approved in the Company's last electric rate case order?

A. In MPSC Case No. U-21585, the Company requested a line clearing spending level of $125.086 million. Company witness Pamela L. Bolden testified in that case that the HVD allocation would be $12.294 million for the 2025 calendar year and $11.972 million for the 2026 calendar year, which equated to $12.240 million in the 2025 test period (March 2025 through February 2026).

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 2026 calendar year and test year spending level, for which it is requesting cost recovery, in the LVD line clearing subprogram?

A. The Company is projecting LVD line clearing expenses of $152.967 million in the 2026 calendar year and $174.844 million in the test period, as shown in Figure 17 below, and in Exhibit A-170 (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 2026 calendar year and test period for each category as identified in Figure 17 below:

FIGURE 17
LVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

	2026 Calendar		Test Period	
Categories	**Expenses**	**Line Miles**	**Expenses**	**Line Miles**
Full Circuit Clearing	$135,674,820	7,891	$156,029,100	9,019
Repetitive Outage	$1,057,600	40	$1,005,067	36
CEMI Clearing	$500,000	34	$450,000	31
First Zone Clearing	$1,000,000	55	$883,333	50
LCP Zonal Clearing	$800,000	27	$729,938	24
Demand Work	$2,250,000	44	$2,100,000	40
Brush Control	$3,500,000	405	$3,666,667	422
Line Clearing Admin	$8,184,287	n/a	$9,980,209	n/a
Total	**$152,966,707**	**8,496**	**$174,844,314**	**9,622**

Q. What expense is associated with more aggressive line clearing on targeted three phase lines?

A. The expense associated with more aggressive line clearing on targeted three phase lines is contained in the full circuit clearing category of work in the amount of $4.172 million for the 2026 calendar year spending level, which is eight months (8/12ths) of the test period incremental expense, shown as Year 1 in Figure 18 below.

Q. How was the expense associated with more aggressive line clearing on targeted three phase lines calculated?

A. The Company estimates that one-fifth of the targeted three phase lines, or about 1,100 miles, will have canopy removal each year through the five-year vision timeframe. In its canopy removal study in 2022, the Company observed an average contractor cost increase of 35% per mile cleared. This cost assumption was utilized across the 1,100 estimated annual miles considering the percentage of total hours worked by local crews and out-of-state crews and an assumed split of on-cycle miles and backlog miles. The vision miles and incremental expense for canopy removal on targeted three phase lines is displayed in Figure 18 below:

FIGURE 18
VISION MILES AND INCREMENTAL EXPENSE FOR CANOPY REMOVAL ON TARGETED THREE PHASE PRIMARY

Vision Year	Cycle Miles	Backlog Miles	Total Miles	Incremental Cost per Mile	Incremental Canopy Removal Expense ($M)
Year 1	550	550	1,100	$5,689	$6.258
Year 2	660	440	1,100	$5,553	$6.108
Year 3	770	330	1,100	$5,320	$5.852
Year 4	880	220	1,100	$5,136	$5.649
Year 5	990	110	1,100	$4,909	$5.399
Total	**3,850**	**1,650**	**5,500**	**$5,321**	**$29.267**

Q. What spending level for the LVD line clearing subprogram was approved in the Company's recent electric rate case orders?

A. The approved spending level for the LVD line clearing subprogram in the Company's recent electric rate case orders is outlined in Figure 19 below:

FIGURE 19
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[8]

[8] Includes wildfire risk mitigation expenditures.

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, and U-21585?

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, and U 21389. In the test period for Case No. U-21585 (March 2025 through February 2026), the Company plans to spend $125.087 million for its Line Clearing Program and an additional $0.321 million for wildfire risk mitigation line clearing as projected in Company witness Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585 and the Commission's Order in that case dated March 21, 2025, page 93. Figure 20 below outlines each MPSC Case No. authorized spend and actual spend. Over this timeframe, the Company invested $19.973 million in its Line Clearing Program above the authorized spend amount.

FIGURE 20
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[9]	$125.408[10]	$0.000
Total	January 2021 - February 2026	$522.287	$542.260	$19.973

[9] Includes wildfire risk mitigation expenditures.
[10] Projected spend.

Q. How did the Company project spending for the 2025 calendar year, the 2026 calendar year, and the test period (May 1, 2026 through April 30, 2027)?

A. The 2025 calendar year spending projection in the Company's 2024 Electric Rate Case No. U-21585 totaled $125.408 million for both LVD and HVD programs, including wildfire risk mitigation expenditures. The Company sought an increase for the 2025 calendar year based on the fifth year of the five-year spending plan presented in MPSC Case Nos. U-20697, U-20963, U-21224, and U-21389 with adjustments in the HVD and LVD subprogram totals from previous filings. For this case, projected test period spending was derived from operational intelligence by Forestry Operation's Senior Manager, Manager of Strategic Planning and Performance, and other staff members. Values presented in Exhibit A-170 (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 at current level and to reduce the clearing cycle on LVD. As average monthly spending is not consistent during a significant ramp-up period (i.e., crewing may sharply increase at any one time when availability permits), the test period for this case (May 1, 2026 through April 30, 2027) presented in Exhibit A-170 (SES-1) is not calculated using ratios of eight months ($8/12^{th}$) of the 2026 calendar year and four months ($4/12^{th}$) of the 2027 calendar year, but instead driven by the aforementioned operational intelligence (e.g., striking an appropriate rate of crew ramp-up based on vendor availability, field planning resources, and supervision).

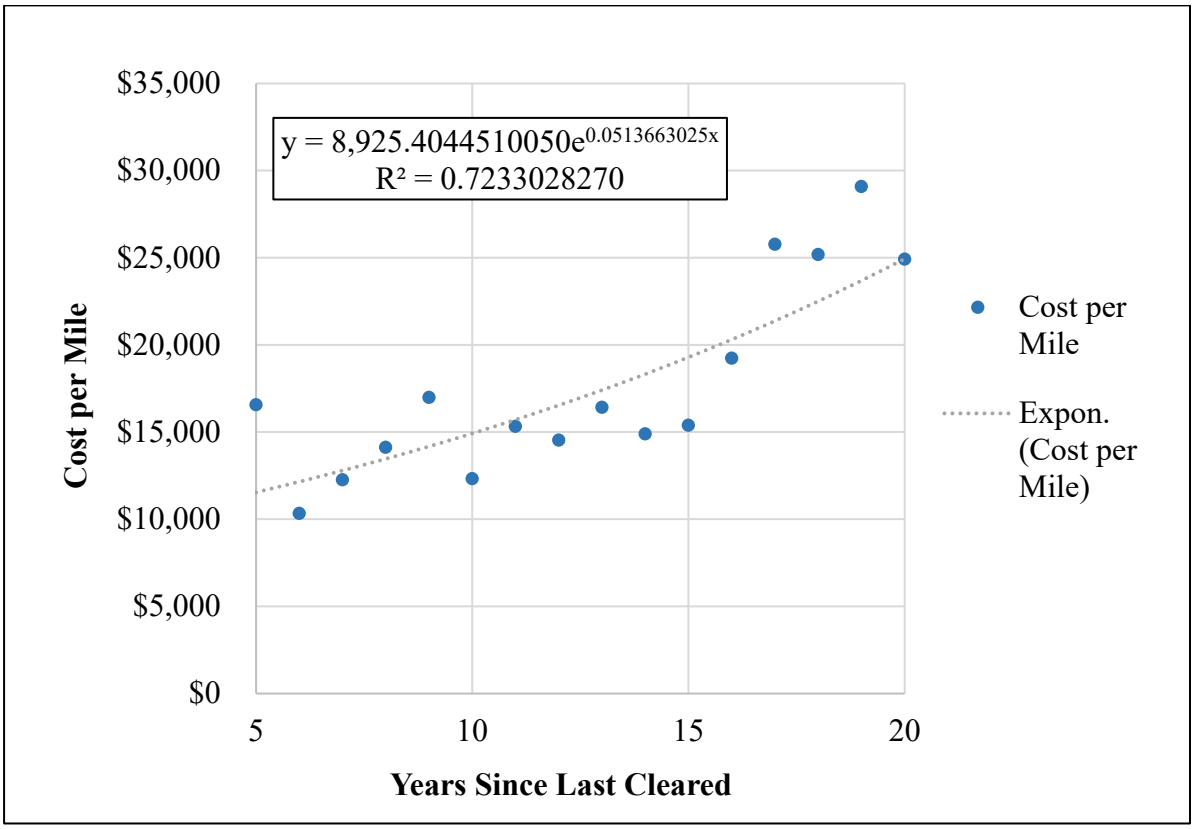
Q. For the test year, what will happen to dollars remaining if the HVD workplan is completed under budget?

A. If the HVD workplan is completed under budget, any remaining dollars for the test year will be allocated to the LVD system to support the Company's vision 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 clearing cycle results in a lower average cost per line mile to clear circuits. 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 for its vision, the Company considered lower costs per mile to maintain circuits on a shorter cycle. Figure 21 below shows the relationship between clearing costs per mile and the number of years between clearings utilizing the most recently available full circuit clearing data from 2024 on circuits last cleared 5 to 20 years earlier. 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 vision includes performing clearing on more cycle circuits starting in 2026, preventing cycle circuits from becoming backlog circuits. This data will continue to be refined, and expense projections updated accordingly.

FIGURE 21
2024 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 the LVD line clearing subprogram?

A. Unit costs over the last five years are provided in Figure 22 below:

FIGURE 22
LVD LINE CLEARING UNIT COSTS

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030
O&M Expense ($M)	$46.10	$75.83	$91.02	$97.79	$99.49
$/line mile	$10,948	$14,364	$14,248	$15,364	$16,499

Q. Please explain the increase in unit costs in recent years.

A. Unit costs decreased significantly in 2020 due to coronavirus pandemic restrictions with decreases in customer interactions with line clearing crews and forestry operations personnel about the planned line clearing work. This permitted clearing operations to proceed in an efficient manner without work stoppages or delays to address customer concerns in the field. As predicted in MPSC Case No. U-20963, the unit cost returned to "normal" levels in 2021 with additional increases as described below.

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.

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 regulatory asset treatment for the funding requirement for the test period above baseline expenditures, identified in Exhibit A-170 (SES-1), column (p), line 27. Figure 23 below summarizes the total O&M expense, baseline expense, and regulatory asset proposal amounts for the test period. This proposed alternate funding mechanism is discussed in further detail in Company witness Daly's testimony on page 34, line 18, through page 36, line 20.

FIGURE 23
LINE CLEARING O&M ALTERNATE FUNDING MECHANISM PROPOSAL
TEST PERIOD

Description	HVD	LVD	Total
Total O&M Expense	$11,839,660	$174,844,314	$186,683,974
Baseline Expense	$11,839,660	$152,606,207	$164,445,867
Regulatory Asset	$0	$22,238,107	$22,238,107

RESOURCING PLAN FOR THE LINE CLEARING PROGRAM VISION

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 personnel and other resources to complete the projected LVD line clearing work if the Commission approves the requested spending level?

A. No. At the time of this filing, the Company has not yet secured the personnel and other resources required to execute the full requested spending level, which is an increase over recent annual expenses and current personnel and resourcing levels.

Q. How does the Company plan to meet the personnel and other resource requirements to complete the projected LVD line clearing work if the Commission approves the requested spending level?

A. A great issue for resource planning is certainty of funding. While the Company will not execute its plans to secure additional personnel and other resources until certainty is attained, the Company is preparing to do so for the test period. The Company has identified three focus areas for this preparation: (i) line clearing contractors; (ii) contract planning and supervision; and (iii) internal staffing.

To ensure the necessary crewing is attained, the Company is working with established line clearing contractors to upskill current and hire additional employees to increase the local crew baseline resourcing level. Additionally, the Company is pursuing contracts with supplemental line clearing contractors to provide out-of-state tree crews to meet the increased crew resourcing level needed to execute the ramp-up plan. Figure 24 below outlines actual crewing from 2020 through 2024 and the projected crewing plan for 2025 through 2030.

FIGURE 24
HVD AND LVD LINE CLEARING CREWING

		HVD	LVD		
Calendar Year	**Data Type**	**Local Crews**	**Local Crews**	**Out-of-State Crews**	**Total Crews**
2020	Actual	41	220	0	261
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	Projected	38	364	0	402
2026	Projected	38	403	53	494
2027	Projected	38	420	120	578
2028	Projected	38	420	158	616
2029	Projected	38	420	158	616
2030	Projected	38	420	158	616

The Company's Forestry Operations and Supply Chain departments are collaborating with its established contract planning vendor for additional planning and supervision resources as well as supplemental contract planning vendors to meet the increased personnel level needed to execute the ramp-up plan.

For in-house staffing, the Company continues to recruit graduates from Michigan Technological University, Michigan State University, and other universities that offer degrees in forestry and/or natural resource management. The plan for internal staffing during the ramp-up is set to meet a level to support the baseline to maintain the steady-state five-year cycle; during the ramp-up period, the Company will utilize contract personnel to meet the increased staffing needs over the baseline resourcing level starting in the test period through the five-year vision.

Q. How does the Company plan to ramp up its LVD line clearing spending and full circuit clearing work for the 2026 calendar year and test period?

A. The projected 2026 calendar year increase in O&M expense and LVD full circuit clearing miles is provided in Figure 12 above and in Exhibit A-170 (SES-1) for the test period. As Figure 12 indicates, in the 2026 calendar year, the Company projects to clear 7,891 miles in its full circuit clearing subprogram, which is 1,783 more miles (29% higher) than the projected 2025 full circuit clearing mileage. The Company projects that it will need 92 additional contractor line clearing crews above the 2025 crewing level to accomplish this plan in the 2026 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 expects to 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-21870

REVISED EXHIBIT

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Clearing O&M Expense
2020-2024 Historical and 2025-2030 Projected

Case No.: U-21870
Revised Exhibit No.: A-170 (SES-1)
Page: 1 of 1
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Electric System	Expense Type	Year	2020	2021	2022	2023	2024	2025 Calendar Year	2026 Calendar Year	2027 Calendar Year	2028 Calendar Year	2029 Calendar Year	2030 Calendar Year	Total O&M Expense Test Period 5/1/26-4/30/27	Baseline O&M Expense Test Period 5/1/26-4/30/27
				Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
2	**Electric HVD**			**$9,169,948**	**$10,739,347**	**$10,987,343**	**$11,301,449**	**$10,729,853**	**$12,204,000**	**$11,986,720**	**$11,545,541**	**$11,200,000**	**$11,399,117**	**$11,601,293**	**$11,839,660**	**$11,839,660**
3		Contractor	Maintenance Clearing	$4,511,969	$4,488,246	$5,157,938	$4,775,712	$4,010,456	$4,781,847	$4,886,488	$4,838,099	$4,769,923	$4,840,779	$4,913,800	$4,870,358	$4,870,358
4		Contractor	Brushing - Cut	$2,365,927	$2,797,068	$3,063,144	$3,601,378	$3,704,716	$3,724,000	$3,469,195	$3,052,100	$2,750,000	$2,805,000	$2,861,100	$3,330,163	$3,330,163
5		Contractor	Brushing - Spray	$1,395,683	$2,407,477	$1,565,658	$1,885,968	$2,033,114	$2,490,000	$2,400,000	$2,400,000	$2,400,000	$2,448,000	$2,496,960	$2,400,000	$2,400,000
6		Contractor	Demand Clearing	$110,249	$98,417	$89,478	$41,202	$42,841	$60,000	$60,000	$60,000	$60,000	$61,200	$62,424	$60,000	$60,000
7		Contractor	Noxious Weed Control	$91,873	$95,891	$152,737	$82,545	$87,750	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000
8		Contractor	HVD Contract Planning	Note[1]	Note[1]	$175,749	$294,503	$320,353	$400,000	$408,000	$416,160	$424,483	$432,973	$441,632	$410,720	$410,720
9		Labor	HVD Salaries	$672,387	$751,684	$653,623	$516,139	$452,901	$540,153	$552,037	$564,182	$576,594	$592,165	$606,377	$556,085	$556,085
10		Other	HVD Expenses	$21,859	$100,564	$129,016	$104,003	$77,722	$113,000	$116,000	$120,000	$124,000	$124,000	$124,000	$117,333	$117,333
11			**Miles**	**1,116**	**1,178**	**1,106**	**1,153**	**1,203**	**1,104**	**1,177**	**1,162**	**1,120**	**1,167**	**1,177**	**1,172**	**1,172**
12	**Electric LVD**			**$46,104,489**	**$75,827,808**	**$91,016,131**	**$97,792,024**	**$99,494,748**	**$113,203,000**	**$152,966,707**	**$201,754,636**	**$226,284,918**	**$230,426,753**	**$236,813,097**	**$174,844,314**	**$152,606,207**
13		Contractor	Full-circuit Clearing	$36,613,687	$62,121,855	$76,623,355	$84,128,930	$84,437,501	$96,211,412[1]	$135,674,820	$182,456,463	$205,820,191	$211,461,495	$217,246,123	$156,029,100	$134,728,091
14		Contractor	Repetitive Outage Zone	$1,397,354	$1,711,666	$2,086,904	$1,542,258	$1,187,069	$1,200,000	$1,057,600	$900,000	$900,000	$431,561	$400,000	$1,005,067	$1,005,067
15		Contractor	CEMI Clearing	$695,322	$491,257	$506,985	$306,882	$111,203	$500,000	$500,000	$350,000	$300,000	$100,000	$100,000	$450,000	$450,000
16		Contractor	First Zone Clearing	$974,275	$405,771	$466,566	$492,077	$806,271	$1,000,000	$1,000,000	$650,000	$600,000	$200,000	$200,000	$883,333	$883,333
17		Contractor	LCP Zonal Clearing	N/A	N/A	N/A	N/A	$1,049,717	$1,000,000	$800,000	$589,814	$500,000	$100,000	$100,000	$729,938	$729,938
18		Contractor	Demand Clearing	$1,281,844	$3,329,375	$2,737,654	$2,058,822	$2,235,640	$2,500,000	$2,250,000	$1,800,000	$1,710,976	$1,400,000	$1,476,192	$2,100,000	$2,100,000
19		Contractor	Brushing - Spray	$1,538,898	$3,072,427	$3,302,319	$3,396,227	$3,491,649	$3,500,000	$3,500,000	$4,000,000	$4,500,000	$4,500,000	$4,750,000	$3,666,667	$3,666,667
20		Contractor	Distribution Contract Planning/Sup	Note[2]	Note[2]	$1,300,689	$2,274,692	$2,708,070	$2,436,000	$2,662,200	$4,435,170	$5,139,355	$5,242,143	$5,346,985	$3,626,866	$3,253,190
21		Labor	Distribution Salaries	$2,509,359	$3,994,189	$3,120,678	$2,877,300	$2,809,333	$3,787,884	$4,279,163	$5,066,666	$5,188,266	$5,312,784	$5,440,291	$5,027,082	$4,541,664
22		Other	Distribution Expenses	$1,093,749	$701,269	$870,981	$714,837	$658,295	$1,067,704	$1,242,924	$1,506,524	$1,626,130	$1,678,769	$1,753,505	$1,326,261	$1,248,257
23			*LVD Full-circuit Miles*	3,679	4,647	5,653	5,758	5,400	6,108[1]	7,891	10,885	12,814	13,588	14,837	9,019	7,872
24			*LVD Subprogram Clearing Miles*	294	238	247	165	209	244	199	149	137	75	75	181	181
25			*LVD Subprogram Spray Miles*	238	395	488	443	421	413	405	454	501	491	508	422	422
26			**LVD O&M Miles Total**	**4,211**	**5,279**	**6,388**	**6,365**	**6,030**	**6,765**	**8,496**	**11,488**	**13,452**	**14,154**	**15,420**	**9,622**	**8,475**
27	**Electric Total**		**O&M Expense**	**$55,274,437**	**$86,567,155**	**$102,003,474**	**$109,093,473**	**$110,224,601**	**$125,407,000**	**$164,953,427**	**$213,300,177**	**$237,484,918**	**$241,825,870**	**$248,414,390**	**$186,683,974**	**$164,445,867**
28		Contractor	Clearing	$48,042,502	$75,539,544	$90,884,760	$97,029,806	$97,673,165	$111,072,259	$149,793,103	$194,791,476	$217,506,090	$221,495,036	$227,454,639	$169,552,960	$148,251,951
29		Contractor	Brushing - Spray	$2,934,582	$5,479,904	$4,867,977	$5,282,195	$5,524,763	$5,990,000	$5,900,000	$6,400,000	$6,900,000	$6,948,000	$7,246,960	$6,066,667	$6,066,667
30		Contractor	Contract Planning	Note[2], Note[3]	Note[2], Note[3]	$1,476,438	$2,569,195	$3,028,422	$2,836,000	$3,070,200	$4,851,330	$5,563,839	$5,675,115	$5,788,618	$4,037,586	$3,663,910
31		Labor	Salaries	$3,181,745	$4,745,873	$3,774,301	$3,393,439	$3,262,235	$4,328,037	$4,831,200	$5,630,847	$5,764,859	$5,904,949	$6,046,668	$5,583,167	$5,097,749
32		Other	Expenses	$1,115,609	$801,833	$999,997	$818,840	$736,017	$1,180,704	$1,358,924	$1,626,524	$1,750,130	$1,802,769	$1,877,505	$1,443,594	$1,365,590
33			**O&M Miles**	**5,326**	**6,457**	**7,494**	**7,518**	**7,233**	**7,869**	**9,673**	**12,650**	**14,572**	**15,321**	**16,597**	**10,794**	**9,647**
34			HVD Cost/Mile	$8,219	$9,117	$9,932	$9,801	$8,919	$11,054	$10,184	$9,936	$10,000	$9,768	$9,857	$10,102	$10,102
35			LVD Cost/Mile	$10,949	$14,363	$14,248	$15,364	$16,500	$16,733	$18,005	$17,562	$16,822	$16,280	$15,358	$18,172	$18,007
36	**LVD 7-year effective cycle**		LVD Target Cycle Miles	8,362	8,362	8,632	8,699	8,714	8,791							
37			LVD O&M Miles	4,211	5,279	6,388	6,365	6,030	6,765							
38			Capital Clearing Miles	258	252	221	169	270	300			7-year effective cycle strategy retired				
39			Percent of 7 Year Cycle	53%	66%	77%	75%	72%	80%							
40			Effective Cycle Years	13.1	10.6	9.1	9.3	9.7	8.7							

Note[1]: Includes Wildfire Risk Mitigation expenditure and miles
Note[2]: HVD Contract Planners were not recorded separately in 2020 - 2021
Note[3]: LVD Contract Planners were not recorded separately in 2017 - 2021

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

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 October 29, 2025, she served an electronic copy of the documents, subject to a Protective Order, upon the persons listed in Attachment 1 as noted therein.

- **Revised Testimony of Consumers Energy Company's witnesses Stacy H. Baker (Direct - Redacted) , Patrick D. Daly (Rebuttal), Jeffrey A. Myrom (Direct), Jennifer M. Partlan (Direct), Andrew R. Snider (Direct), and Sara E. Stewart (Direct);**
- **Revised Public Exhibits A-208 (PDD-63), A-213 (PDD-68), A-214 (PDD-69), A-216 (PDD-71), A-217 (PDD-72), A-169 (JMP-4), and A-170 (SES-1); and**
- **Exhibit A-230 (JAM-6).**

Crystal L. Chacon
Digitally signed by Crystal L. Chacon
Date: 2025.10.29 16:21:11 -04'00'

Crystal L. Chacon

Subscribed and sworn to before me this 29th day of October 2025.

Melissa K. Harris
Digitally signed by Melissa K. Harris
Date: 2025.10.29 16:21:40 -04'00'

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-21870

Party	Email Address
Administrative Law Judge	
Jonathan F. Thoits	thoitsj@michigan.gov
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. Mark R. Ruszkiewicz, Esq.	gary.genschjr@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com spencer.sattler@cmsenergy.com evan.keimach@cmsenergy.com mark.ruszkiewicz@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.	singha9@michigan.gov orrism@michigan.gov cozorta1@michigan.gov taylorn10@michigan.gov clarkA55@michigan.gov sonneveldtd@michigan.gov
Michigan Public Service Commission Staff	
*Mike Byrne *Bill Stosik *David Chislea *Bob Nichols *Nick Revere *Lori Mayabb	byrneM@michigan.gov stosikb@michigan.gov chislead@michigan.gov nicholsb1@michigan.gov reveren@michigan.gov mayabbl@michigan.gov
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
Consultant for the Attorney General	
*Sebastian Coppola	sebcoppola@corplytics.com
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 *Tanya Stasio *Jordan Burt *Tyler Comings *Caroline Palmer *Rick Bunch *Julielyn Gibbons *Matt Bandyk *Sean Clark	holly@troposphere legal.com chris@troposphere legal.com tjandrews@troposphere legal.com natasha@troposphere legal.com tanya.stasio@aeclinic.org jordan.burt@aeclinic.org Tyler.comings@aeclinic.org cpalmer@synapse-energy.com rbunch@5lakesenergy.com jgibbons@5lakesenergy.com mbandyk@synapse-energy.com sean@troposphere legal.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21870

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
Consultant for Kroger	
Justin Bieber	jbieber@energystrat.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
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 *Alexandria Miskho *Heidi Peng *Willow Perlick *Aashney Shah	templeton@uchicago.edu jschuhardt@uchicago.edu eyoung28@uchicago.edu amiskho@uchicago.edu hhpeng@lawclinic.uchicago.edu willowperlick@lawclinic.uchicago.edu aashney@lawclinic.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
Consultants for ABATE	
*James Dauphinais *Jessica York *Christina Hildebrandt	jdauphinais@consultbai.com jyork@consultbai.com childrebrandt@consultbai.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 Walmart, Inc. ("Walmart")	
Melissa M. Horne, Esq.	mhorne@hcc-law.com

* Receives Confidential Materials