STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ADELLA F. CROZIER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ADELLA F. CROZIER

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No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Adella F. Crozier (she/her/hers). My business address is One Energy Plaza, Detroit, MI 48226. I am employed by DTE Energy Corporate Services LLC, a subsidiary of DTE Energy Company (DTE Energy), within Regulatory Affairs as a Director.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Metallurgical Engineering from Iowa State University and a Master of Business Administration degree from the University of Chicago. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q4. What is your work experience?

A4. Prior to my employment at DTE Energy, I was employed by LTV Steel Company (LTV) in various roles including Metallurgical and Quality Control Engineer in positions of increasing responsibility for different product lines. My last role with LTV was as Product Manager in the Sales and Marketing Department. In this role, I had responsibility for managing the relationship between the Sales and Marketing Department and one of LTV's major production plants. As part of my responsibilities, I ran financial and engineering analyses related to product line offerings.

I joined DTE Energy in 2003 as a Technological Specialist in the Fossil Generation Department's Engineering Support Organization. In 2004, I was promoted to Supervisor – Mechanics and Metallurgy. In 2005, I joined the Regulatory Affairs Department as Manager of Special Projects. In this role, I assisted the Environmental Affairs Department with their portions of Detroit Edison's general rate case filings and served as a member of several workgroups related to Governor Granholm's 21st Century Energy Plan and Capacity Need Forum. I helped with the Company's implementation of Michigan's 2008 energy legislation, particularly those areas related to energy optimization. I managed several Detroit Edison energy optimization filings as well as provided witness testimony regarding the revenue requirement of several energy optimization plans and reconciliations. During this time, I also assisted the case managers of general rate cases.

I was promoted to Manager of Electric Regulatory Strategy in 2013 where my responsibilities included research of regulatory matters and my team also provided management of DTE Electric's general rate cases.

I was promoted to Director within Regulatory Affairs in 2016. In this role, I was responsible for managing the Company's activities at the Michigan Public Service Commission (MPSC or Commission) and at the Federal Energy Regulatory Commission (FERC). Members of my team that work on State activities provided case management for some of the Company's compliance filings, research activities pertinent to our electric utility, and coordinated activities related to the state's 2016 energy legislation.

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Q5. What are your current duties and responsibilities?

A5. I remain a Director within DTE Energy's Regulatory Affairs Department. Currently, in this role, my team is responsible for managing the Company's state filings and activities at the Michigan Public Service Commission (MPSC or Commission). Members of my team also provide various research activities pertinent to our electric utility and provide cost of service and revenue requirement modeling.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in the following DTE Electric cases:

U-15806	Detroit Edison's Energy Optimization (EO) Plan
U-15806 A	Detroit Edison's EO Amended Plan
U-16358	Detroit Edison's 2009 EO Reconciliation
U-16359	Detroit Edison's 2010 EO Reconciliation
U-16737	Detroit Edison's 2011 EO Reconciliation
U-20561	DTE Electric 2019 Rate Case
U-18232	DTE Electric 2020 Renewable Energy Plan (REP) Amendment
U-18091	DTE Electric 2021 PURPA Avoided Costs
U-20836	DTE Electric 2022 Rate Case
U-21193	DTE Electric 2022 Integrated Resource Plan (IRP)
U-21297	DTE Electric 2023 Rate Case
U-18091	DTE Electric 2024 PURPA Avoided Costs

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Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to:

- Provide an overview of the Company's entire general electric rate case including a summary of the drivers for filing this case at this time, and the amount of the Company's projected revenue deficiency starting January 1, 2025;
- Review the overall methodology used to develop the Company's projected test year amounts in this case;
- Address the following ratemaking and policy; propose unique or different ratemaking treatments; respond to prior Commission orders; highlight noteworthy regulatory issues; or address topics of interest expressed by stakeholders:
  - The Company's future securitization of costs associated with the Company's tree trimming surge;
  - Recovery of certain outage credits paid to customers;
  - Corporate memberships and costs included for ratemaking as ordered in the Company's last general rate case, U-21297; and
- Introduce the Company's other witnesses.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am supporting the following exhibit:

Exhibit	Schedule	Description
A-27	Q1	Corporate Memberships

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Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

Case Overview

Q10. Can you summarize the circumstances that have led to the Company's request for rate relief?

A10. Yes. DTE Electric is pursuing two strategic imperatives. First, we are working to rebuild, modernize, and automate our 46,000 miles of electric circuits (the "grid") to achieve reliability that is better than industry average by 2029. Second, we are replacing aging coal plants with modern power generation assets, such as wind turbines, large scale solar arrays, and large battery installations. Both pursuits represent multi-year initiatives that can only be accomplished with the support of our customers, the Michigan Public Service Commission (MPSC), and the investors that provide the capital needed to fund the necessary investments.

Q11. What benefits should the Company's customers expect to realize from these initiatives?

A11. The benefits to DTE Electric's customers of these strategic initiatives are:

- Fundamental improvements in the reliability of the grid and in its ability to accommodate electric vehicles and other distributed energy resources.
- Reduced carbon emissions from more efficient and cleaner sources of power generation.

Q12. What is the expected level of capital investment for grid modernization and generation transformation initiatives?

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A12. Fully realizing these benefits will require significant investment - approximately $9 billion of investment in the grid and $7 billion of investment in cleaner generation between 2024 and 2028. We appreciate that we are asking our customers to support these investments in the form of bill increases. However, as described below, we believe that these investments will generate significant benefits and value to our customers.

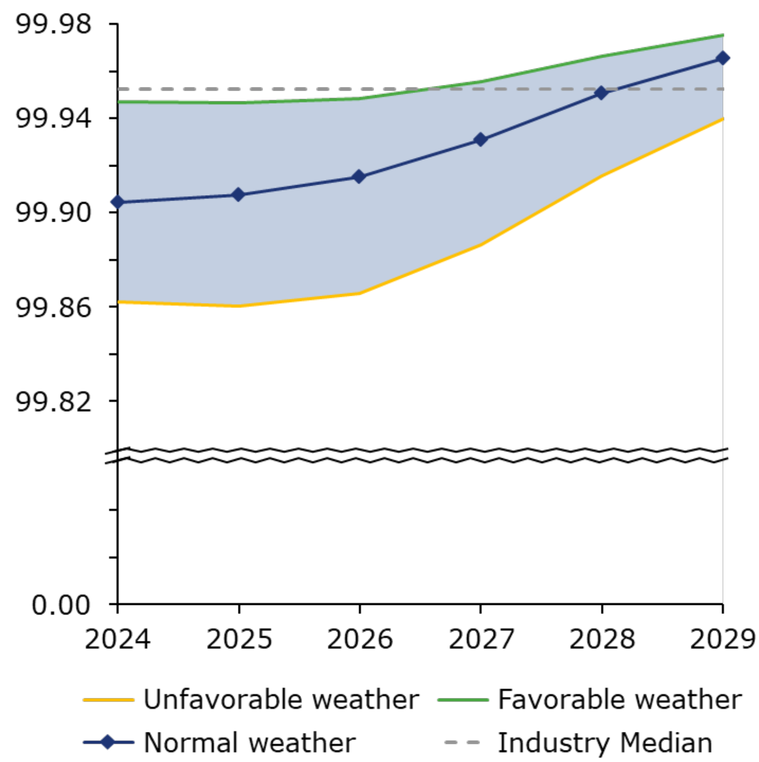
Q13. Specifically, what improvements is DTE Electric expecting to achieve relative to grid reliability?

A13. These system investments, for which this rate case represents the next step in the multi-year journey described above, can provide tremendous benefits to our customers and to the state. More specifically, DTE Electric is focused on improving reliability for our customers – reducing power outages by 30% and cutting outage time in half in the next five years. As explained in more detail by the Company's Distribution Operations (DO) witnesses in this case (i.e., Company Witnesses Kryscynski, Deol, Elliott Andahazy, Hartwick, and Steudle) the Company is strengthening, rebuilding, and/or using technology to create a smarter, stronger, more resilient grid that will reliably deliver the energy our customers demand and deserve. Our commitment can be summarized as: *"30% fewer… 50% faster… by 2029."*

As can be seen in Figure 1 and Figure 2, this commitment translates to better than industry median performance by 2029 for Average System Availability Index and

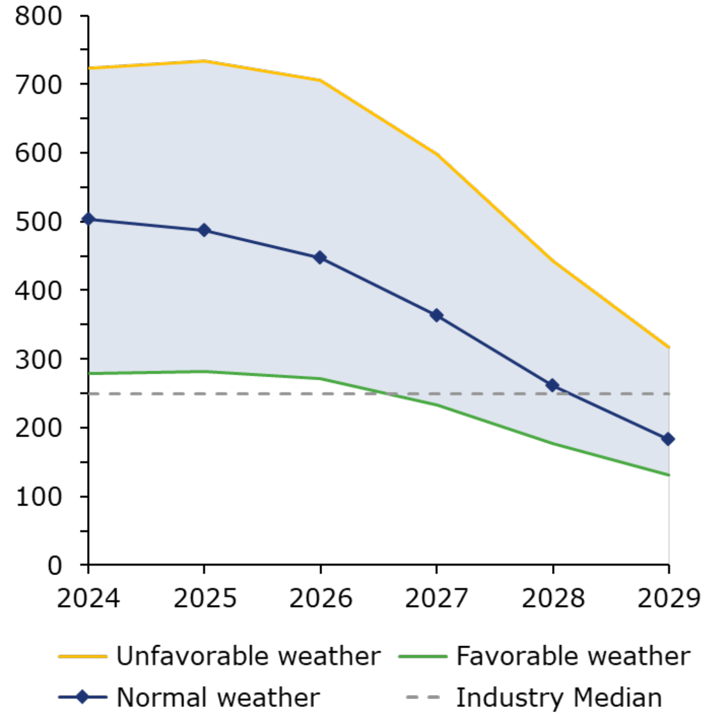
All-Weather SAIDI[1]. These projections are based on the Reliability Model described by Company Witness Kryscynski.

Figure 1. Projected Average System Availability Index (%)



[1] System Average Interruption Duration Index

Figure 2. Projected All-Weather SAIDI (or Average Outage Minutes Per Customer) (minutes)



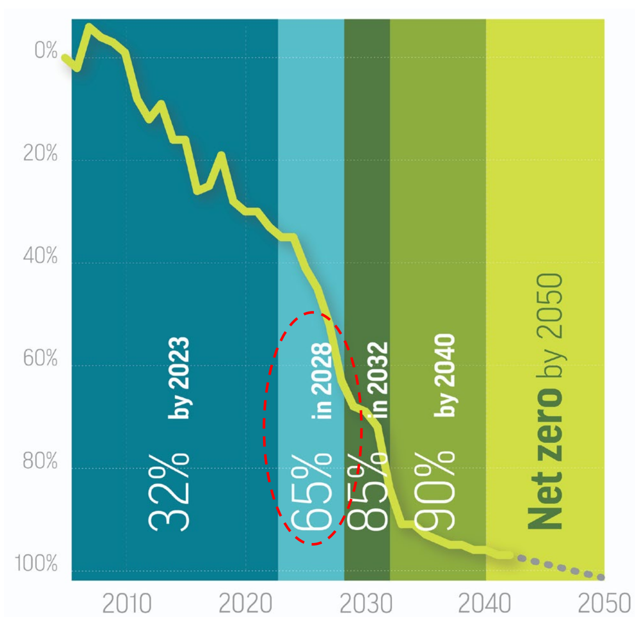
Q14. Besides the benefit of improved reliability, are there other potential benefits that customers could realize from DTE Electric's grid modernization initiative?

A14. Yes. These forecasted improvements will not only substantially improve DTE Electric customers' qualitative experience but have the potential to unlock significant economic value. The publicly available Interruption Cost Estimator (ICE) Calculator, which was developed by the Lawrence Berkeley National Laboratory, provides one approach to examine and estimate the potential value that might be realized through improved electric system reliability. While not definitive, based on the ICE Calculator the Company's forecasted reliability improvements could generate more than $15 billion of positive economic impact. Realizing such estimated benefits is dependent upon achieving improved reliability through continued investment in the Company's grid, enabled by timely recovery of capital expenditures.

Q15. What benefits will customers realize due to DTE Electric's generation modernization initiative?

A15. DTE's planned investments in new generation assets will enable the transition to cleaner generation and allow a reduction of $C0_2$ emissions of 65% by 2028 when compared to the 2005 baseline, as shown in Figure 3.

Figure 3. DTE Green Generation Journey



Q16. Can you summarize the Company's plans to execute on the proposed investments?

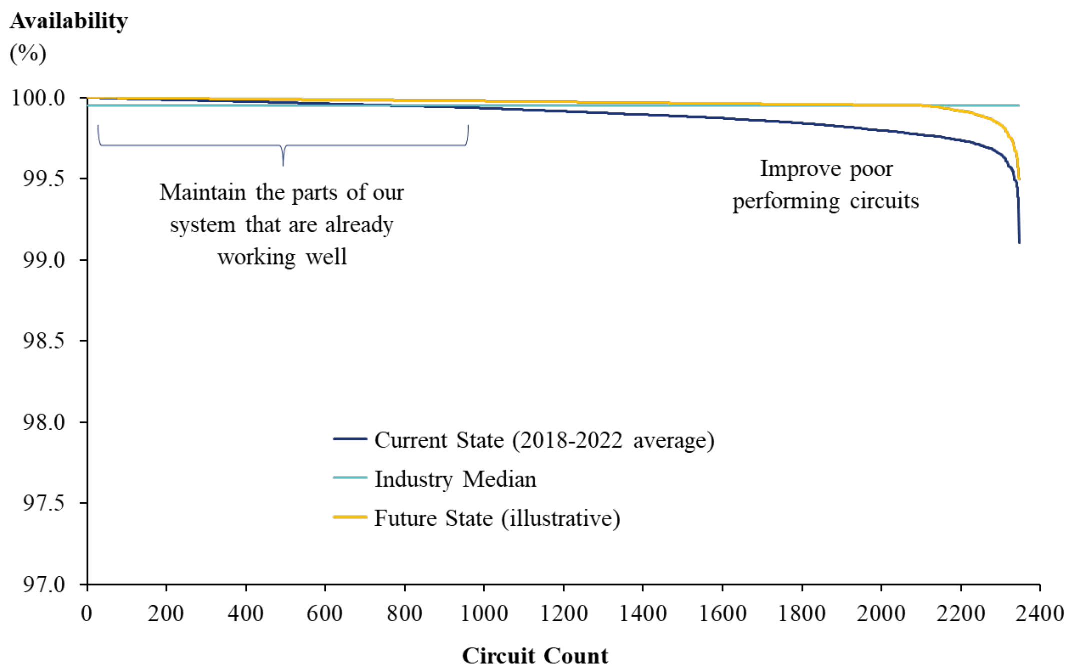
A16. The Company is fully prepared to execute our plans and have built an organization that is capable of making these historic investments. We have proven our ability to significantly ramp up project and program execution as evidenced by the increase in electric distribution strategic capital deployment over the last few years.

Our specific capital investments and associated plans are discussed in detail by the Company's DO witnesses identified earlier, and can be summarized as follows:

- Maintain high performing circuits so that they remain high performing circuits
- Fundamentally improve low performing circuits
- Build capacity for the future

Figure 4 illustrates this strategy as we look at the performance of our circuits and the 46,000 miles of electric lines that make up the DTE Electric grid covering 7,600 square miles of DTE Electric service territory.

Figure 4. Circuit Availability (2018-2022 average)[2]

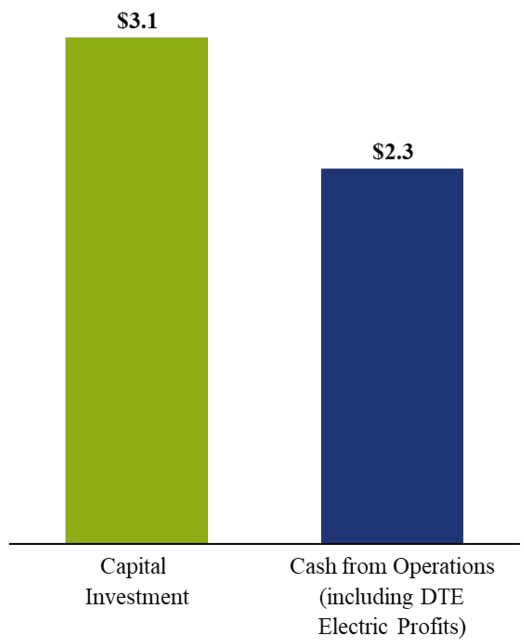


Q17. How will investors support these initiatives?

A17. Investors will provide the necessary capital to execute DTE Electric's planned investments assuming reasonable recovery of costs through the Company's rates. As shown in Figure 5, to execute its investments DTE Electric requires cash in excess of what it generates internally from its operations (cash that includes DTE Electric profits). As such, external investors are needed to provide the incremental capital that enables us to execute our plans.

[2] Only circuits with at least 50 customers are shown on chart

Figure 5. DTE Electric 2023 Cashflow[3]



Q18. Have there been any reliability impacts from ongoing grid modernization efforts?

A18. Yes, where investments have been made, we are seeing benefits. For example, as supported by Company Witness Elliott Andahazy and shown in Figure 6, the Company's 4.8 kV Hardening program has led to a 61% reduction in frequency of outages (SAIFI[4]) on hardened circuits compared to non-hardened circuits.

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[3] Source: DTE Electric Form 10k
[4] System Average Interruption Frequency Index

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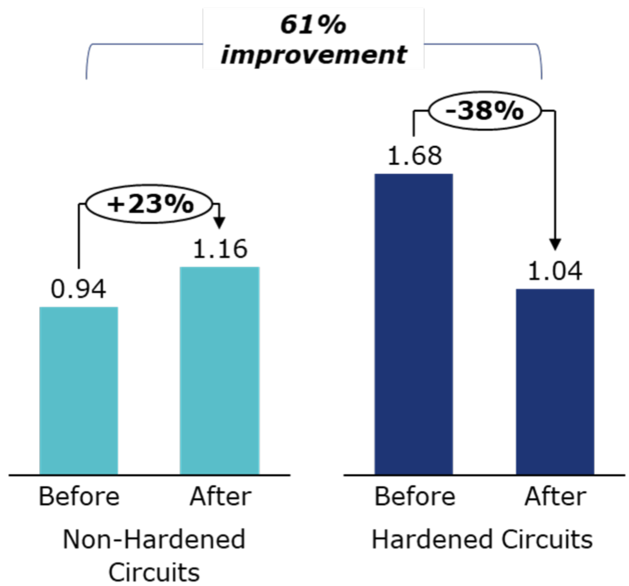
Figure 6. Outage frequency of circuits 1-year post 4.8 kV hardening

(# of outages; All-Weather SAIFI)



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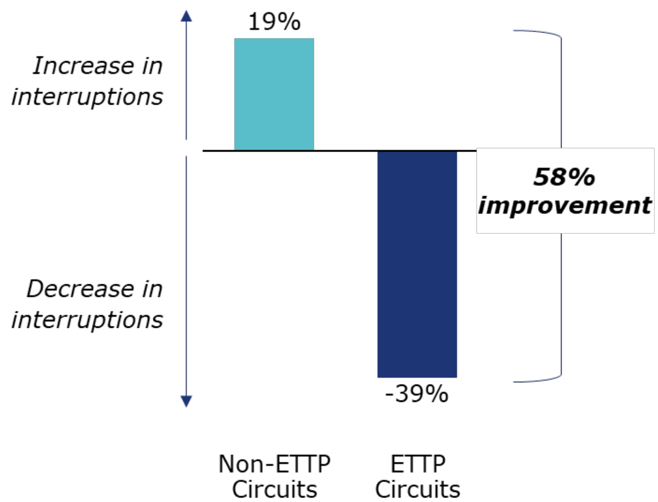
Similarly, as supported by Company Witness Steudle and shown in Figure 7, the Company's Enhanced Tree Trim Program (ETTP) has resulted in a 58% reduction in tree related outages for circuits for which the program has been deployed.

Figure 7. Change in tree-related customer interruptions 1-year post trim

(% change)



Q19. How does this case support the strategic initiatives described previously in your testimony?

A19. This case supports approximately $2.6 billion of total new capital investment in 2025, the projected test year in this case, as well as additional capital in the bridge and historical test year. The Company is also seeking approval to extend its Distribution Infrastructure Recovery Mechanism (IRM), with associated revenues, through 2027. As discussed previously, DTE will need additional support from customers to execute on its capital plans and achieve the forecasted reliability improvements. That support takes the form of the requested rate relief, which is

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driven primarily by capital investments. When combined with other factors described in the case, the total requested test year base rate relief is approximately $456 million, of which $321 million (70% of the total) is related to capital recovery and financing ($285 million for direct capital costs and $36 million for the increased cost of debt and changes in capital structure).

Q20. What is the present status of the Company initiatives you described?

A20. In prior years, the Company has made investments in line with its strategic plans to improve reliability and provide cleaner generation, even if those investments were not fully authorized for recovery in a prior rate case. Specifically, as of 2024 the Company anticipates that actual net plant in-service will be approximately $775 million higher than what is currently authorized for recovery in rates. Given the carrying costs associated with this plant in-service balance, timely recovery of prudent capital investment is necessary to support the Company continuing to make the investments that are needed to improve reliability and transition to cleaner generation.

With that said, and as described by Company Witness Foley, the Company acknowledges the Commission’s desire that, within a reasonable range of flexibility, the Company make capital investments consistent with Commission approvals in rate cases. To that end, in this case the Company is proposing to extend its Distribution IRM through 2027 and indicating its support for an expansion of the IRM in the test year (2025). Such an approach would have the dual benefits of both ensuring that investments are made consistent with Commission orders and supporting timely recovery of those investments.

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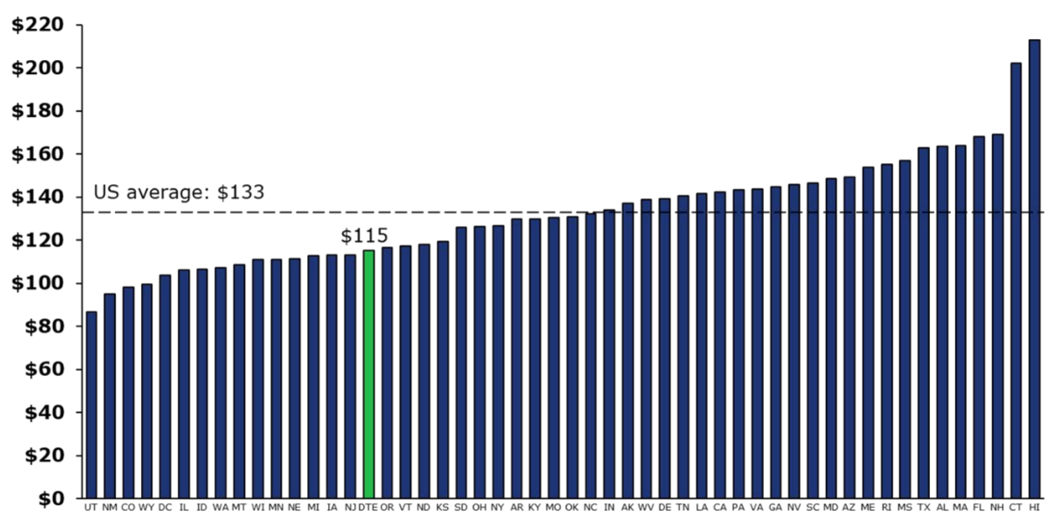
Q21. How will the Company's grid modernization and generation transformation initiatives impact the cost to its customers?

A21. The Company understands that with the requested rate relief it is asking its customers to pay more to support improvements in reliability and the transition to cleaner generation. According to the Energy Information Administration (EIA) average bills for DTE Electric customers remained below the national average in 2023, as seen in Figure 8. Specifically, in 2023 DTE Electric's Residential Electric Bills were 13% below the national average, and in 2022 were 11% below the national average[5].

Figure 8. 2023 Average Residential Electric Bills[6]



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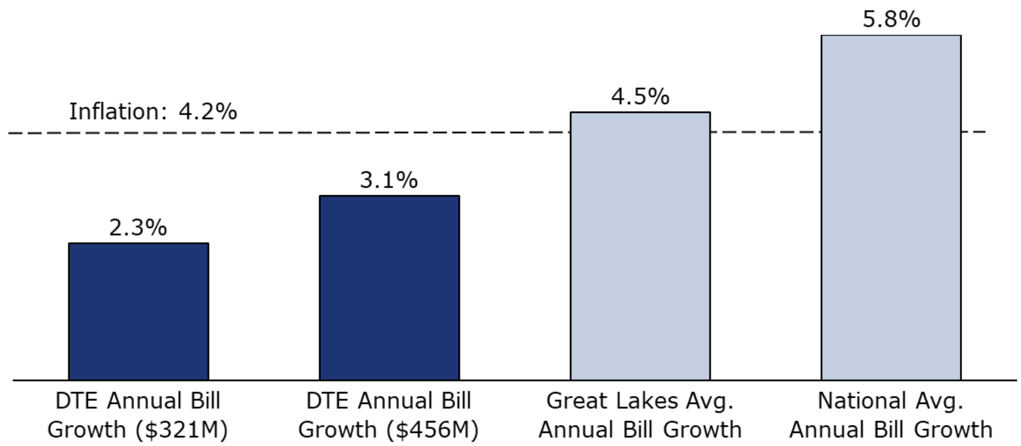
[5] DTE Electric 2022 Average Residential Bill: $118.45; 2022 National Average Residential Bill: $132.90. Source: EIA 861M

[6] Source: EIA 861M

In addition to having below average bills, since 2021 DTE Electric's residential bill growth has remained below the rate of inflation and below the rate of increase for peers in both the Great Lakes and nationally. Rate relief as proposed by the Company in this case would continue this trend. The requested test year rate relief of approximately $456M would result in an increase of 37 cents/day for the average residential customer and would translate to average annual bill growth of 3.1% since 2021., This is below the projected level of average inflation of 4.2% over the same time. Between 2021 and 2023, Great Lakes region residential electric bill growth has been 4.5% per year, and national electric bill growth has been 5.8% per year.

Rate relief of $321M, which would cover the recovery and financing costs for the capital as described above, would result in a bill CAGR over that same period of 2.3%. This is illustrated below in Figure 9.

Figure 9. Average Residential Bill Growth Since 2021[7]



In summary, the rate relief sought in this case will allow DTE Electric to take another important step on its multi-year journey toward improved reliability and cleaner generation. As discussed previously, we are already realizing the reliability benefits of our grid investments where they have been made, but there is much work to be done. Approval of the requested rate relief supports the Company's plan to deliver reliability that is better than industry average by 2029 and unlock potential economic value, while also continuing the transition to cleaner generation.

Q22. Can you elaborate on how the requests in this general rate case filing support the Company's strategic imperatives described above?

A22. This rate case represents the Company's continued commitment to improved reliability and innovation. The Company is seeking approval of significant

[7] 12-month trailing average through May 2021; DTE forecasted through Jan 2025, peers actual through November 2023; inflation is actual CPI through Jan 2024 and core inflation projection from the Federal Open Markets Committee for 2024

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infrastructure investments to improve the reliability and resilience of its electric distribution system as detailed in its 2023 Distribution Grid Plan filed in Case No. U-20147. This involves redesigning, hardening, and rebuilding antiquated infrastructure, modernizing how the electric grid is monitored and operated, and performing preventive and proactive maintenance and tree trimming at standards that reflect today's operating conditions, including security risks and more extreme weather. These investments will not only reduce how often and how long customers experience power outages but will also enable the Company to support greater optionality for customers in adopting technologies such as batteries, solar, and electric vehicles (EVs).

To support innovation during this period of transformational change in the energy industry, the Company is also proposing new technology deployments, including enhanced information technology capabilities to reduce costs and improve the customer experience; energy storage in the form of batteries; non-wires alternatives; and expanded programs to support deployment of EVs. The Company's generation fleet continues to evolve towards cleaner resources with new renewable energy facilities and the recently approved conversion of the Belle River Power Plant to a natural gas peaking resource. The Belle River Unit 1 conversion is scheduled for completion in 2025 while Belle River Unit 2's conversion is scheduled for completion in 2026. DTE Electric has retired six of its coal-fired facilities, which accounts for all of its Tier 2 coal units (Marysville, Harbor Beach, Conners Creek, River Rouge, St. Clair, and Trenton Channel). In addition, the Company's Integrated Resource Plan (Case No. U-21193) resolved in 2023 will require the development of additional renewable energy and battery

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storage resources, while accelerating the retirement of its remaining two coal-fired facilities, Belle River and Monroe. The Company committed to all these actions prior to the State's recently passed legislation establishing a 100% clean energy standard by 2040 and as such, is well positioned for compliance.

Q23. Why has DTE Electric filed this general rate case at this time?

A23. DTE Electric strives to provide safe, reliable, and affordable electric service to its customers. In pursuit of these objectives, DTE Electric seeks to deliver reasonable and appropriate compensatory returns to DTE Energy shareholders while maintaining the Company's financial health. As discussed above, DTE Electric has undertaken a major capital investment program to improve reliability and resilience, most notably for the distribution system and is also moving toward cleaner sources of generation. However, the Company's existing rates and projected electricity sales cannot sustain this level of infrastructure investment without a rate increase. The level of investments undertaken by the Company since 2022 and projected to be spent through the projected test year in this case requires the Company to make this filing. The only way that DTE Electric can adequately provide the required service levels that our customers desire and deserve is by being financially healthy. The Company's current authorized rates are not expected to provide DTE Electric with adequate revenues to make necessary infrastructure investments while providing a reasonable opportunity to earn a fair return on equity beginning in January 2025.

Q24. What are the measures used to determine the Company's financial health?

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A24. Maintaining DTE Electric's financial health requires that the Company has a reasonable opportunity to earn its cost of capital, that the Company has a well-balanced capitalization (no less than 50% equity to total permanent capitalization), and that the Company is able to maintain its A/Aa3/A+ credit ratings for senior secured debt from the three major rating agencies. These preconditions are necessary to ensure DTE Electric has full access to capital markets at reasonable rates, terms, and conditions regardless of business cycle timing or industry conditions. As discussed by Company Witness Lepczyk, without full access to capital markets at reasonable terms and conditions, the cost of providing utility services can increase significantly.

Q25. Why is the Company's financial health important for customers?

A25. To attract the capital necessary for the prudent operation and maintenance of its facilities, the Company must be able to demonstrate its ongoing financial health. Inadequate rates will ultimately result in higher financing costs and have a significant negative impact on the ability to adequately serve our customers and maintain the integrity of the Company's electric distribution and generation assets. This negative impact will occur because greater expenditures would be required to support financing costs, and therefore, would not be available for system maintenance or customer service. Similarly, inadequate funding for capital and maintenance programs, over time, would result in the deterioration of DTE Electric's generation and distribution infrastructure, ultimately resulting in reduced system reliability and service quality.

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Thus, it is essential to DTE Electric's financial health that the ultimate cost that customers are asked to pay for the Company's services generate sufficient cash flow from operations to fund the necessary capital expenditures to maintain and improve service as well as pay a reasonable dividend.

Q26. Does DTE Electric's continued implementation of infrastructure maintenance and investment programs provide additional benefits to customers and the region?

A26. Yes. DTE Electric has an important positive economic impact on the communities it serves. DTE Electric is one of the largest employers in Southeast Michigan with over 4,800 employees. Through the Pure Michigan Business Connect campaign, the Company utilizes the services of numerous local contractors and vendors. DTE Energy spent over $2.5 billion with Michigan based companies in 2023. Through property taxes, DTE Electric contributes to the financial health of local communities. In the historical test year, DTE Electric paid approximately $280 million in property taxes to Michigan communities. To maintain facilities, comply with various regulations, implement its Distribution Grid Plan, and continue the transformation of its generation fleet, DTE Electric continues to make major capital investments in the communities in which it operates. Thus, DTE Electric supports additional job growth opportunities and provides continuing and incremental tax revenue for our local communities.

Q27. Does DTE Electric provide assistance to customers who have trouble paying their utility bill or provide opportunities to customers needing assistance to participate in some of the Company's offerings?

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A27. Yes. The Company has programs to help customers who are having trouble paying their utility bill as well as offerings that help low-income customers participate in some of the Company's other programs. For example, DTE Electric works to help customers maintain service and reduce arrears and also offers residential income assistance (RIA) and low-income assistance (LIA) credits to help vulnerable customers manage utility bills. These are discussed by Witness Sparks along with details regarding a percentage of income payment plan pilot the Company launched in 2022. Additionally, Witness Bennett discusses our electric vehicle program which will help income qualified customers. Lastly, any customer taking service under the Company's MIGreenPower (Rider 17) tariff, as well as any other interested parties, can support a low-income donation pilot on a monthly basis or as a one-time contribution. These voluntary contributions provide fully subsidized subscriptions to low-income customers who are eligible to participate.

Requested Relief

Q28. What rate relief was approved in the Commission's Order in the Company's last general rate case, Case No. U-21297?

A28. The Company's last general rate case, Case No. U-21297, was filed in February 2023 requesting $618.5 million in rate relief. This deficiency assumed that the Company's proposed IRM would be approved. In the Commission's December 1, 2023 Order, DTE Electric received approval for $368 million in rate relief and approval to establish an IRM.

Q29. What rate relief is DTE Electric requesting in this case?

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A29. As calculated by Company Witness Vangilder, DTE Electric expects a revenue shortfall of $456.4 million for the January 1, 2025 through December 31, 2025 projected test year. As supported by various Company witnesses, factors contributing to this shortfall are the revenue requirement associated with increased investments made in plant and the associated depreciation and property tax increases as well as the impact of inflation on DTE Electric's O&M and borrowing costs.

Q30. Can you highlight some of the major investments and expenses included in the Company's request for rate relief?

A30. This general rate case sets forth the rationale, spending, timing, and expected customer benefits associated with significant investments in distribution, generation, and customer service. Several programs to highlight are summarized below.

- Strategic infrastructure investments in substations, poles, wires, transformers and other electric distribution assets to modernize equipment, support growth in customer demand in specific areas, improve worker and public safety, and reduce the frequency and duration of power outages. This also includes plans to accelerate the conversion of the 4.8 kV system to a higher voltage, ramping up the pole top maintenance program, and increased investment in distribution automation and telecommunications technologies.
- Continuation of the multi-year tree trimming "surge" program that reduces outages on circuits trimmed to the new, more protective standard. The continuation of the Commission-approved tree trimming program will

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allow the Company to complete the surge, which is expected in 2025. This program remains critical to improving reliability and resilience across the system and is foundational to the Company's overall efforts to improve reliability.

- Conversion of Belle River Power Plant's fuel source from coal to natural gas, consistent with the IRP Order in Case No. U-21193, which included preapproval of the Belle River Fuel Conversion project.
- Plant removal associated with the retirement and decommissioning of power generation assets at Harbor Beach, Conners Creek, River Rouge, St. Clair, and Trenton Channel Power Plants. With the Company's final Tier 2 plants having been retired in 2022, DTE Electric is committed to the removal of these retired steam generating units. The process involves three primary activities, namely decommissioning, decontamination, and demolition. Witness Guillaumin addresses this project in detail in her testimony.

Q31. What investments is the Company making to promote greater levels of advanced technology and customer satisfaction?

A31. The Company is working to deploy advanced technologies in all areas of its business as well as furthering its commitment to deploy proven technology to improve our customers' experience with DTE Electric's services. Examples are briefly described below:

- Energy storage projects proposed for the Energy Supply portfolio include two grid-scale battery applications. One is the continuation of the 14 MW Slocum battery pilot project slated to replace retiring peaking generation

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located in Trenton, Michigan. The other project, also located in the City of Trenton, is a 220 MW battery that is consistent with the build plan included in the Company's 2022 IRP planned course of action. This project will be located at the site of the recently retired Trenton Channel Power Plant. Witness Guillaumin addresses this project in detail in her testimony.

- Distribution Operations also continues to evaluate different use cases for energy storage. Examples include the use of batteries to help relieve certain substation overloads and a battery trailer which can be sited in place of traditional portable generators. Witness Hartwick addresses these projects in detail in her testimony.
- As outlined in the Company's information technology (IT) plans, the customer IT portfolio of investments prioritizes the enhancement of customer experiences and increased operational efficiencies. Witness Hatsios addresses these customer service IT plans in detail in his testimony.

<u>Rate Case Methodology</u>

Q32. Can you describe the methodology the Company is using to support its projected test year positions and its recommendations in this case?

A32. Yes. DTE Electric has used actual historical data as the point of departure for most estimated cost levels for the projected test year. These historical costs were then adjusted for the impact of inflation. As has been DTE Electric's practice in prior rate cases, certain other costs reflect specific estimates or projections where general impacts of inflation alone would be insufficient to capture known changes. For example, some of these include, but are not limited to, capital expenditures for new

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plant and uncollectible expense. All these cost components and the circumstances involved are explained and supported by other Company witnesses.

Q33. What historical and projected test year periods are being used by DTE Electric for purposes of calculating its projected revenue deficiency?

A33. The historical test year used by DTE Electric is the calendar year ended December 31, 2022. This 12-month period was then normalized and adjusted for known and measurable changes, as supported by the Company's witnesses in this case, to arrive at the Company's January 1, 2025 through December 31, 2025 projected test year. As this case is being filed in early 2024, the Company has included 10 months (January – October) of actual capital investments in the 2023 bridge period.

Q34. Are there any new recovery mechanisms being requested in this rate case?

A34. Yes. Through the testimony of Witness Foley, the Company is requesting a new storm restoration O&M cost sharing mechanism to better align storm restoration O&M cost recovery with the actual costs incurred by the Company.

Through the testimony of Witness Foley, the Company is also proposing an extension of the IRM approved by the Commission in Case No. U-21297. In Case No. U-21297, the Company requested a roughly three-year IRM starting concurrent with the forward test year in that case (December 1, 2023) and extending through calendar year 2026. The Commission approved the first two years (December 1, 2023 through December 31, 2025) of the proposed IRM but not the last (calendar year 2026). The Company is requesting the IRM be extended to cover calendar years 2026 and 2027. In addition, the Company is indicating its support for an

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expansion of the IRM in 2025 if the Commission finds it appropriate to do so as a way to grow the stakeholder benefits realized through the IRM.

<u>Tree Trimming Surge</u>

Q35. Has the Commission previously approved tree trim "surge" funding in the Company's recent rate cases?

A35. Yes. In the Company's last four general electric rate cases (Case No. U-20162, Case No. U-20561, Case No. U-20836, and Case No. U-21297), the Commission approved the deferral of "surge" amounts for the Company's tree trimming program. These "surge" amounts represent an increase in annual funding above the baseline tree trimming O&M and have been supporting the Company's goal of achieving a five-year trim cycle for its distribution system.

The Commission approved $43.7 million in surge funding for calendar year 2025 in the Company's most recent general rate case, U-21297. As discussed in detail by Company Witness Ms. Steudle, this "surge" in tree trimming spending was established to occur over an approximately seven-year period (2019 – 2025). At the program's termination, the Company expects to maintain all circuits on-cycle to the enhanced tree trimming specification, as discussed by Witness Steudle.

Q36. Is the Company requesting that the Commission approve incremental funding for the 2025 surge?

A36. Yes. The program remains on track to be completed in the seven years originally contemplated but as detailed and supported by Witness Steudle, the Company has identified a funding gap to complete the surge in 2025 and maintain on-cycle miles

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at the intended 5-year cycle. As such, the Company is requesting an incremental $87 million be approved for the 2025 surge deferral. To complete the tree trim surge program, the Company is requesting that the Commission approve a total surge funding deferral of $131 million for calendar year 2025. Witness Steudle provides a detailed explanation of the funding gaps and the proposal to complete the surge and maintain on-cycle miles.

Q37. What other parameters did the Commission specify related to the deferral of the tree trimming surge amounts in previous orders?

A37. In the Case U-20162 May 2, 2019 Order, the Commission specified that the return earned on the tree trim surge regulatory asset deferrals would accrue at the short-term debt rate. Lastly, the Commission stated that the Company may seek recovery of the regulatory asset in a future rate case or through securitization.

Q38. Has the Company sought the securitization of any of the previously deferred tree trimming assets yet?

A38. Yes. In Case No. U-21015, the Company requested securitization of $116.2 million of its tree trim deferred asset balance through June 30, 2021. The requested amount represented the total qualified assets of $156.9 million ($43.3 million in 2019, $74.1 million in 2020, and $38.3 million through June 30, 2021, plus interest of $1.2 million) net of deferred federal income tax charges (DFIT) of $40.6 million. The Commission approved the securitization of and recovery up to the total qualified costs for the tree trim deferred asset of $156.9 million inclusive of DFIT and the Company has securitized that expense.

Q39. How has the Company treated the tree trim surge regulatory asset in this general rate case filing?

A39. The Company has included a "return on" the tree trim surge regulatory asset at the cost of permanent capital (i.e., long-term debt and equity) included in this case. Witness Lepczyk discusses why the Company believes the return on should be comprised of both permanent debt and equity. The Commission's Order in the Case No. U-21015 securitization filing required the proceeds from the securitization be used to retire both permanent debt and equity for the tree trim surge regulatory asset. Consistent with that determination, the Company should be allowed to recover its actual financing cost in a commensurate manner. The revenue requirement for the deferred amount is calculated by Company Witness Vangilder on Exhibit A-11, Schedule A1.1 using debt and equity costs supported in this case by Witness Lepczyk.

Q40. When does the Company anticipate making its next securitization filing for the tree trim surge regulatory asset?

A40. Previously, the Company proposed securitizing balances once they reach approximately $150 million. Current projections show the Company will reach this cumulative balance in 2025, the proposed last year of the surge program. However, since the upfront costs associated with securitization bonds are sizable and largely fixed, the Company intends to wait until the projected 2025 surge completion before making its next securitization filing. The larger deferred balance will more efficiently spread the fixed costs and reduce overall securitization costs to customers. Although a securitization filing capturing costs through early 2025 is technically feasible in 2025, the Company also needs to consider the size of the anticipated surge amounts through the remainder of the surge scheduled to end late in 2025. Given the fixed costs of securitizing and the time between reaching a $150 million balance and the conclusion of the program, DTE Electric is planning to file a final tree trim related securitization after the surge program concludes in 2025, capturing all expenditures not previously securitized.

Outage Credit Recovery

Q41. Is the Company currently recovering the costs of any credits paid to customers for outages?

A41. No. In the last two general rate cases, the Company has not included any expenses for the cost of credits it has paid to customers for outages.

Q42. Did DTE Electric propose a framework for the future inclusion of these costs in either of its last two general rate cases?

A42. Yes. In Case U-20836, the Company proposed that those credits paid for outages caused by events outside DTE Electric's control be deferred for subsequent recovery starting with the final order in that case. On page 366 of the order in that case, the Commission directed:

> *…DTE Electric to work with the Staff toward the full development of the Staff's proposed limited recovery of outage credits. The Commission upholds the company's responsibility to timely restore electric service to customers in all circumstances under the Commission's Service Quality and Reliability Standards for Electric Distribution Systems (Mich Admin Code, R 460.701-752) and customers' entitlement to an outage credit on their power bill in circumstances where the company fails to do so. However, it*

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is reasonable that the company have the ability to recover outage credits when the outage was caused by customer negligence or the transmission system operator, among other limited circumstances as developed in collaboration with the Staff.

Q43. Did the Company and Staff meet to discuss outage credit cause codes and Company recoverability?

A43. Yes. Prior to the filing of this case, the Company and Staff discussed outage cause codes as well as the reasonableness of recoverability for credits paid as a result of outages that exceed the outage duration limits and those outages exceeding the outage frequency limits outlined in the Commission's Service Quality and Reliability Standards (rules R460.744 and R460.745 respectively).

Q44. What is the Company's position regarding the outage causes that should have their related credits recovered by the Company?

A44. The Company's position is that recoverability of the credits paid for outages differs based on which of the two broad categories of outages triggers the payment: 1) duration limit or 2) frequency limit.

DTE Electric believes that credits paid for outages that exceed the duration limit should include the following outage causes:

- Transmission operator or other utility
- Public interference
- Animal interference

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The Company also believes that for credits paid to customers for exceedance of the outage frequency limits, that recoverability would include the following outage causes in addition to the two above:

- Ice
- Lightening
- Wind
- Other weather

Q45. What is the rationale for including weather related events for recoverability when there is an exceedance of outage frequency limits but not recommending the same for exceedances of the duration limit?

A45. The rationale is that the Company controls the restoration time when there is a weather event but not the frequency with which weather events occur.

Q46. How is the Company proposing to recover the expense for credits related to those outage causes approved by the Commission for recovery?

A46. The Company's proposed recovery treatment of outage credit costs is consistent with its original proposal in Case No. U-20836. With the Commission's approval of the underlying outage causes that result in recoverable credits, the Company will defer the costs related to those credits starting after an order in the instant case. The deferred amounts would be reviewed for reasonableness and prudency in the subsequent general electric rate case. Only after the deferred amounts are approved would the Company begin amortizing and recovering them. Witness Uzenski describes the deferral mechanism including the amortization period in her testimony.

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Q47. Does the Company have a proposal for how recoverable credits related to frequent outages would be calculated?

A47. The Company would like to spend more time with Staff to design a methodology for the recovery of these credits but has an initial proposal. If a customer meets the criteria for the outage credit based on outage frequency, there will likely be a mix of underlying causes. Though mathematically simple to determine the percentage of the outage credit that is recoverable, it will be expensive and complicated to implement an algorithm into the billing system to calculate a unique percentage to apply to each $38 credit that is being deferred for recovery. The Company proposes that a common percentage be applied to all outage credits paid for outage frequency exceedances that reflects some analytics from the previous year. In this way, a simple and consistent factor can be applied to each outage credit paid for frequency exceedances, avoiding the need for complicated and costly system programming.

It would be less costly to analyze the prior year's data and apply a common percentage than to analyze each payment real-time and apply a unique factor. The Company would like to work with Staff to develop a methodology that is reasonable and able to be implemented without billing system complexities.

Corporate Memberships

Q48. How does the Company determine which corporate memberships to acquire?

A48. The Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, clean and reliable energy. Decisions regarding

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which memberships to obtain are typically made by individual business units. A list of the corporate memberships included in DTE Electric's O&M expense are shown on Exhibit A-27, Schedule Q1. As shown in this exhibit, each membership generally falls under the auspices of one business unit.

Q49. Has the Commission provided guidance on how the Company should support its Corporate Memberships in this and future rate cases?

A49. Yes. In its November 18, 2022 Order in Case No. U-20836 on page 306, the Commission directs the Company as follows:

"The Commission directs DTE Electric to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest."

Further, in its December 1, 2023 Order in Case No. U-21297, on page 221, the Commission directs the Company as follows:

"*Therefore, to ensure continued recovery of these corporate membership fees, DTE Electric shall provide in its next general rate case a detailed description of how these organizations specifically impact/benefit customers as outlined by the DAAOs, which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization.*"

Q50. Has the Company itemized the projected costs associated with membership fees and included justifications for why these costs are in customers' best interest?

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A50. Yes. Exhibit A-27, Schedule Q1 includes the customer benefits and cost for each membership included in the Company's projected test year. The exhibit is seven pages with pages 1 - 2 displaying, in alphabetical order, the corporate memberships which are nondiscretionary. Pages 3 – 7 display, in alphabetical order, those memberships which are discretionary. The descriptions include the specific benefit these memberships offer. Additionally, corporate memberships which are discretionary and exceed $100,000 are further supported by other witnesses in the case representing the primary business unit that utilizes the membership. Exhibit A-27, Schedule Q1 columns (d) and (e) provides the witness names along with their associated business unit for those customer and membership benefits.

Q51. Do any of the membership costs included in the Company's revenue requirement in this case involve lobbying activities?

A51. No. Any memberships, or portions of memberships, related to lobbying activities are excluded from DTE Electric's revenue requirement. Witness Uzenski supports how certain memberships and their related costs have been excluded. As mentioned above the costs shown on Exhibit A-27 Schedule Q1 represent the costs that are proposed for inclusion in rates, exclusive of lobbying fees. The amounts have not been adjusted for inflation on Exhibit A-27 Schedule Q1 but are included in the Company's revenue requirement with an inflation adjustment.

Q52. What benefits are realized from DTE Electric's memberships in the organizations listed on Exhibit A-27, Schedule Q1?

A52. In addition to the benefits included in each membership's description and supporting witnesses' testimony (reference column e of Exhibit A-27, Schedule Q1 pages 2 -7), the benefits the Company and its customers receive from the memberships listed in Exhibit A-27, Schedule Q1 pages 2 through 7 generally fit into one or more of the following broad categories:

- Benchmarking - helps the Company understand how its performance and practices compare to its peers,
- Best practices - provides insights into industry best practices and potential opportunities for implementation based on those insights,
- Research – provides access to research that the Company would otherwise have to perform on its own, and leads to access to information at a lower cost than if each member organization performed the research on their own,
- Networking – helps build relationships with peers that improves the flow of communication between people and companies leading to a greater awareness of industry trends, emerging technologies, emerging issues, and resources.

Q53. Are you providing additional support for any of the corporate memberships requested for recovery?

A53. Yes. As noted above, Exhibit A-27, Schedule Q1 lists the supporting witness for non-discretionary memberships over $100,000. The one membership that I am supporting is the Edison Electric Institute (EEI).

In addition to our operating groups (e.g., Distribution, Generation), the Company leverages EEI to the benefit of its customers through many of the Company's workstreams (e.g., IT, Supply Chain) as outlined below. EEI members are afforded the opportunity to establish connections with other companies through the EEI network. Some examples of how the Company's EEI participation benefits customers include:

- Mutual assistance coordination across the nation which enables DTE Electric to quickly secure resources for storm restoration. The industry has no other mutual assistance structure;
- Information on technology industry security initiatives and best practices;
- Assistance identifying and networking with diverse suppliers specific to the utility industry as well as sharing best practices regarding supplier diversity;
- Benchmarking on utility-driven economic development;
- Knowledge building regarding FERC Order 2222 (addressing Distributed Energy Resource participation in electricity markets) and its implications for utility system preparation and operation;
- Best practice sharing from transportation electrification programs around the nation; and
- Learning from industry experts and leaders on important topical subjects such as battery operations and risk mitigation, decarbonization, and non-wire alternatives.

<u>Introduction of Other Witnesses</u>

Q54. How will the Company present evidence in support of its requested relief in this case?

A54. The Company will present its case through 28 witnesses, including myself, as described below (in alphabetical order).

1) Mr. Robert A. Bellini, Manager – Community Lighting, supports the energy forecast for outdoor lighting; the development of the proposed rate design

for the outdoor lighting rate schedules (municipal lighting and other) as well as supports the reasonableness of the historic and projected Community Lighting O&M and the Community Lighting capital expenditures. He also discusses the preventative maintenance programs and outage restoration activities for community lighting.

2) Ms. Pina Bennett, Director – Electric Marketing supports the expenditure status for existing Charging Forward programs and pilots and discusses the Transportation Electrification Plan. She also supports Merchant Fees expense and certain expenditures related to the 2023 full time-of-day roll out; and the Electric Regulated Marketing O&M expense.

3) Mr. Shawn D. Burgdorf, Manager of the Power Supply Strategy & Modeling – Generation Optimization, establishes the projected wholesale market energy sales revenue net of fuel.

4) Mr. Michael S. Cooper, Director - Compensation, Benefits & Wellness, presents an overview of benefit expense for DTE Electric for the 2022 historical test period and the January 1, 2025 through December 31, 2025 projected test period. He supports the Company's pension costs, other post-employment benefits (OPEB) costs, active employee health care and other employee benefits costs; supports labor cost escalation assumptions assumed in the projected period; provides an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall reasonableness of its total

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compensation; provides an analysis of the reasonableness of the current total compensation levels; describes the components of the Company's short and long-term incentive plans and supports the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five executives. In addition, Witness Cooper demonstrates that the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

5) Mr. Jeffery C. Davis, Expert – Nuclear Strategic Business Operations, supports the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2022. He also discusses and supports the reasonableness of the projected nuclear O&M and capital expenditures for the interim forecast period and the 12-month projected test period ending December 31, 2025. In addition, he supports the reasonableness of the projected Nuclear Surcharge for the projected test period ending December 31, 2025.

6) Mr. Satvir Deol, Director – Substation Operations, supports, as reasonable and prudent, the historical capital expenditures for 2022 and projected capital expenditures for 2023 through December 31, 2025, in the distribution strategic investment category of Infrastructure Redesign and Modernization and discusses programs associated with the Company's IRM discussed by Company Witness Foley.

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7) Ms. Morgan Elliott Andahazy, Director – Project Management Organization, supports, as reasonable and prudent, the historical capital expenditures for 2022 and projected capital expenditures for 2023 to December 31, 2025, in the distribution strategic category of Infrastructure Resilience and Hardening. In addition, her testimony will include support for specific programs included in the IRM proposed by Company Witness Foley.

8) Mr. Keegan Farrell, Manager - Demand Response (DR), discusses the development of DR efforts that DTE Electric is conducting and provides support for the expenditures and activities associated with the continuation of existing programs and pilots, as well as the Company's proposals for new pilots. He also discusses the DTE Insight Program and projected capital expenditures.

9) Mr. Neal T. Foley, Director - Regulatory Affairs, describes the key components of the Company's proposal in this case for the scope and duration of IRM... He also supports a proposal to establish a Storm Restoration Cost Sharing Mechanism.

10) Ms. Margaret E. Guillaumin, Plant Director, Energy Supply Operations Performance, supports the reasonableness and prudency of the O&M and capital expenditures for Energy Supply steam power generation, hydraulic power generation (Ludington), and other power generation for the historical

test year ended December 31, 2022, the 24-month bridge period ending December 31, 2024, and the 12-month projected test period ending December 31, 2025. She provides a review of the Fossil Generation base coal unit availability performance for five years prior and five years following the projected test year in this instant case. She also discusses how the Environmental Protection Agency's Steam Electric Effluent Limitation Guidelines Rule affects required coal-fired generation investment and supports the historical 2022 level of capital expenditures on a plant level basis and the forecast of capital expenditures planned for 2023 through December 31, 2025.

11) Ms. Shannen M. Hartwick, Director of Automation supports, as reasonable and prudent, the historical capital expenditures for 2022, the projected capital expenditures for 2023 through December 31, 2025 in the distribution strategic investment category of the Technology and Automation Pillar, and the programs associated with the Company's IRM.

12) Mr. Michael J. Hatsios, Director – Customer Service Operations supports the reasonableness and prudency of a subset of the capital projects in the Company's Customer IT Portfolio. Specifically, he discusses the details and benefits to customers of those projects that align with DTE Electric's priorities to save customers money, enhance the customer experience, and promote and provide energy efficiency (EE) and renewable energy opportunities for customers. He also supports the Customer Service O&M for the 2022 historical test year and the 2025 projected test period.

13) Mr. Brian L. Hill, Director –Southwest Regional Customer Operations and Scheduling & Coordination, supports, as reasonable and prudent, the historical capital expenditures and proposed capital expenditures related to base capital programs (emergent replacements, customer connections, relocations, and others). In addition, he provides an explanation of the Company's purchase and use of Portable Generators and an update on MISS DIG (which is not a capital program or expenditure) reporting changes made since Case No. U-21297.

14) Mr. Allen J. Kryscynski, Acting Director – Distribution Operations Regulatory Strategy and Grid Modernization, supports the historical Operations and Maintenance (O&M) expenses related to electric distribution activities for 2022 historical period and for the projected test period 12-months ending December 31, 2025, the Distribution Operations' Global Prioritization Model, Infrastructure Investment and Jobs Act funding grants, updates the Distribution Operations approach to Environmental Justice, as well as supports several other DO related issues.

15) Mr. Robert J. Lee, Manager - Environmental Strategy, describes the status of two significant Environmental Protection Agency regulations: the Steam Electric Effluent Limitation Guidelines Rule and the Coal Combustion Residuals Rule which impact the Company's coal-fired power plants.

16) Mr. Timothy J. Lepczyk, Assistant Treasurer and Director – Corporate Finance, Insurance and Development supports DTE Electric's projected capital structure and the cost of its long and short-term debt to be used in the determination of DTE Electric's overall rate of return in this proceeding.

17) Mr. Markus B. Leuker, Manager – Corporate Energy Forecasting, provides the Company's current electric sales, maximum demand, and system output forecast for the period 2023-2028, including the projected 12-month test period January 1, 2025 through December 31, 2025. He discusses the outlook for the national and local economy which is the basis of the forecast. Witness Leuker also describes how the forecast of electric sales, maximum demand and system output is developed and supports the reasonableness of the electric sales forecast used by DTE Electric in this proceeding.

18) Mr. Habeeb J. Maroun, Regulatory Strategy Consultant – Revenue Requirements Department, presents Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test year ending December 31, 2025. He also provides an Alternate Cost of Service Study (Alternate COSS) with DC Fast Charging (DCFC) as a separate class, as required by the Commission in its December 1, 2023 Order in Case No. U-21297. He also supports revenue requirement calculations for: (1) customer-related costs, (2) capacity charge by customer class, and (3) IRM by voltage class.

19) Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, supports DTE Electric Fuel Supply's and Midwest Energy Resources Company's (MERC)

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operations and maintenance expense and capital expenditures for the twelve months ended December 2022 historical actual, and as projected for 2023 through December 31, 2025. He also addresses how the Company's transition from coal generated electricity will affect MERC transshipment operations and the railcar fleet for the Company as well as the planned retirement of operations at MERC.

20) Mr. Pankaj Sharma, Director – Information Officer within the Information Technology Services organization, discusses the IT Capital investment framework and planning process that drives prioritization of both single and multi-year projects and programs; supports the Company's IT capital expenditures beginning with the historic test year and extending through the projected test year; and describes the variances in the actual 2022 capital spend compared to the spend approved in the Company's previous general rate case.

21) Mr. Jason E. Sparks, Director – Revenue Management and Protection supports the details of the Company's Low-Income programs and provides explanation and support for the uncollectible expense. He proposes changes to the Rate Schedule D1.6 tariff provision. He also discusses details of our Low-Income Assistance credits and their impact with the Low-Income Self Sufficiency Program as well as the Payment Stability Plan pilot.

22) Ms. Rachel Steudle, Director of Tree Trim, discusses the importance of and progress made in DTE Electric's vegetation management ("Tree

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Trimming") program; provides details related to the Company's Tree Trimming Surge Program that will deliver on the reliability goals established in the Company's Distribution Grid Plan (DGP); and describes the customer benefits of the Company's Tree Trimming Surge Program to date. In addition, she supports the O&M expenses related to tree trimming efforts for the historical test period ending December 31, 2022, the projected base O&M expenses and the Tree Trim Regulatory Asset Surge funding amount for January 1, 2025, to December 31, 2025.

23) Ms. Theresa Uzenski, Manager – Regulatory Accounting, supports DTE Electric's financial statements for the historical test year ended December 31, 2022, the interim forecast period and a twelve-month projected test period ending December 31, 2025, with certain adjustments necessary for presenting the financial information in the appropriate format for ratemaking purposes. She supports the development of the projected test year adjusted electric operating income based on forecasted changes from the normalized historical electric operating income. She supports that costs recovered from other mechanisms are excluded from the financial statements in this case (including the Renewable Energy Program, and Energy Waste Reduction). She also supports the Corporate Staff Group capital and O&M expenses for the historical and forecasted periods and explains the function of this group including the method for allocating costs to DTE Electric and other DTE Energy subsidiaries through the Shared Asset charge. She also, explains the accounting treatment of the Monroe regulatory asset and amortization over 15 years and requests approval of

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regulatory asset and liability accounts for the Company's storm cost tracker proposal supported by Witness Foley.

24) Mr. Kirk M. Vangilder, Principal Financial Analyst - Revenue Requirements, supports DTE Electric's twelve months ended December 31, 2022 historical revenue sufficiency. In addition, he is sponsoring Net Operating Income (NOI) adjustments for interest synchronization and income tax savings, as well as the revenue conversion factor. Mr. Vangilder is sponsoring DTE Electric's twelve months ending December 31, 2025 projected revenue deficiency. He also calculates the incremental revenue requirement for DTE Electric's Tree Trim Surge Regulatory Asset and the return on the Monroe Regulatory Asset. Lastly, he supports the incremental revenue requirements for DTE Electric's IRM as well as the Company's proposed reconciliation process should a different amount of IRM capital be placed in service than what has been approved.

25) Dr. Bente Villadsen, Principal at The Brattle Group, supports the cost of capital for the Company. Specifically, Dr. Villadsen estimates the cost of equity that DTE Electric should be allowed an opportunity to earn on the equity-financed portion of its regulated utility rate base. Dr. Villadsen's recommendation also considers the business and financial risk of the Company relative to the proxy companies to arrive at her recommendation for the allowed Return on Equity for DTE Electric of 10.5%.

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26) Mr. Aaron Willis, Manager – Regulatory Economics, discusses and supports forecast allocation schedules, power supply costs, rate design, IRM surcharge design, and other tariff changes.

27) Ms. Sherri Wisniewski, Director – Tax Operations, supports the DTE Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal Income Tax, property tax and other general taxes for the 2022 calendar year historical period as well as the twelve months projected test period ending December 31, 2025.

Q55. Does this complete your direct testimony?

A55. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT A. BELLINI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT A. BELLINI

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Robert A. Bellini (he/him/his). My business address is 8001 Haggerty, Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE Electric or Company) as Manager of Community Lighting.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Central Michigan University with a Bachelor of Science degree in Business Administration in 1999. In 2005, I graduated from Oakland University, with a Master of Accountancy degree.

Q4. What is your work experience?

A4. From 2005 until 2008, I was employed by Deloitte & Touche LLP as a Financial Auditor. While employed at Deloitte & Touche, I passed the Certified Public Accountant (C.P.A.) examination and became a licensed C.P.A. in 2007. In 2007, I was promoted to Senior Auditor on client engagements. In this role, I was responsible for tailoring each audit based on a client's industry and the risks inherent in their operations, supervising the audit fieldwork, and communicating the audit issues and results with client management.

In 2008, I joined DTE Energy as a Financial Auditor. My responsibilities included executing both financial and Sarbanes-Oxley (SoX) audits in support of the DTE

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Energy 10-K annual filing under the guidance of our external auditor, PriceWaterhouseCoopers (PWC). In 2010, I was promoted to Senior Auditor. My responsibilities included planning, scoping, and executing both financial and operational audits. In 2013, I was promoted to Principal Supervisor of the Joint Use department. My responsibilities included developing budgets, forecasting, and negotiating joint use agreements with various attaching entities. In 2016, I was promoted to Manager, Joint Use. In 2018, I was promoted to Manager, Community Lighting.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. Yes. I am a registered Certified Public Accountant (CPA).

Q6. What are your current duties and responsibilities?

A6. I am currently responsible for managing the marketing and sales, budgeting and forecasting, planning and construction and asset management for approximately 199,000 DTE Electric-owned streetlights and outdoor protective lights (OPLs). I also manage the maintenance and provision of energy to municipally owned streetlights and the provision of energy-only service to municipalities, in accordance with DTE Electric's MPSC-approved tariffs. DTE Electric's assets related to these services include mercury vapor, metal halide, high pressure sodium, and light-emitting diode (LED) luminaires.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

U-20561	2019 DTE Electric General Rate Case
U-20836	2022 DTE Electric General Rate Case
U-21297	2023 DTE Electric General Rate Case

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support the following topics related to DTE Electric's lighting assets: a) cost recovery of O&M and capital expenditures, and b) rate design. Specifically, I will discuss the following issues:

- Describe the portfolio of Community Lighting assets;
- Support the sales forecast for the various outdoor lighting rates including automated traffic signal (ATS) rates and metered street lighting rates;
- Describe the Company's preventative maintenance programs;
- Discuss the Company's outage restoration activities;
- Support and discuss the Company's actual Community Lighting O&M expenses for the historical period which ended December 31, 2022, and the projected Community Lighting O&M expenses for the 12-month projected test period ending December 31, 2025;
- Support and discuss Community Lighting's actual capital expenditures for the historical period which ended December 31, 2022, and the projected Community Lighting capital expenditures for the 12-month projected test period ending December 31, 2025;

- Discuss the reasonableness of DTE's LED selection methodology as it relates to HID to LED conversions, as well as the disallowance of LED plant costs as ordered in Case No. U-21297;
- Discuss the sunsetting of Community Lighting's installation and maintenance of high-pressure sodium (HPS) technology, and proposed tariff changes;
- Discuss the status of municipal streetlight outage reporting and proposed tariff changes as ordered by the MPSC Commission in Case No. U-21297;
- Support the proposed rate design for the outdoor lighting (municipal and other) and ATS tariff offerings using the lighting model.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-12	B5.5	Projected Capital Expenditures – Community Lighting
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-16	F3	Present and Proposed Revenues by Rate Schedule – 12 months ending December 31, 2025
A-16	F8	Proposed Tariff Sheets
A-25	O1	Community Lighting Outdoor Lighting Outage Duration

A-25	O2	Community Lighting Outdoor Lighting Outage Cost
A-25	O3	HPS to LED Customer Notification Letter
A-25	O4	WP Calculation of $5.8M Disallowance by MI-MAUI in U-21297
A-25	O5	Don McLean DTE HID-LED Selection Methodology Opinion Letter
A-25	O6	DMD – Intersection Performance Summary
A-25	O7	DMD – Revised Rdwy Performance Summary
A-25	O8	Don McLean_Curriculum Vitae
A-25	O9	Gibbons – DTE Energy Response Document & CV

I am sponsoring line 23 within Exhibit A-13, Schedule C5.6, page 1 of 2, and the pages specific to the residential and commercial outdoor protective lighting (OPL) and municipal classes within Exhibit A-16, Schedule F3. This includes pages 46 through 57. On Exhibit A-16, Schedule F8, I sponsor the OPL and municipal tariffs, while Company Witness Willis sponsors the tariffs for the remaining customer classes.

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Community Lighting Assets

Q11. Could you describe the portfolio of Community Lighting assets that DTE Electric owns, operates, and maintains on behalf of its customers?

A11. DTE Electric owns, operates, and maintains approximately 199,000 Community Lighting assets which serve municipal, commercial, and residential customers. Additionally, there are approximately 82,000 streetlights which are owned by municipal customers (E1 Option III), and approximately 6,400 municipal-owned Automated Traffic Signals (E2). Municipal streetlights (E1 Option I and II) include roadway and residential streetlights within municipal and/or city limits. These streetlights owned by DTE Electric are installed at the request of the city or municipality. DTE Electric also installs Outdoor Protective Lighting (OPL) for commercial (D9 Commercial) and residential (D9 Residential) customers. Examples of commercial OPL solutions include parking lot lighting systems (i.e. restaurants or strip malls) and residential OPL solutions such as lights installed on a customer's property. Ownership of Community Lighting assets is detailed in Table 1 below:

Table 1: Community Lighting Assets[1]

Asset Type	Asset Ownership	Rate Type	# Of Assets	Description
Municipal OH & UG Streetlights	DTE Electric	E1 Option I	165,932	DTE Electric owned and maintained system
Municipal OH & UG Streetlights	Customer	E1 Option II	119	Municipal owned and DTE Electric maintained system
Municipal OH & UG Streetlights	Customer	E1 Option III	82,399	Municipal owned and maintained system
Commercial Outdoor Protective Lights	DTE Electric	D9	24,179	DTE Electric owned and maintained equipment
Residential Outdoor Protective Lights	DTE Electric	D9	9,147	DTE Electric owned and maintained equipment
Municipal Automated Traffic Signals (ATS)	Customer	E2	6,436	Municipal owned and maintained equipment

[1] Light counts as of November 1st, 2023

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Q12. Briefly describe the various lighting technologies in service and the movement toward more energy-efficient Company-owned LED lighting technology.

A12. There are 4 lighting types currently in use within DTE Electric's service territory: Light Emitting Diode (LED), High Pressure Sodium (HPS), Metal Halide (MH), and Mercury Vapor (MV), the first three of which are still actively maintained and installed upon request. LED lighting is the most energy efficient lighting type available, while the remaining light types are less efficient in terms of energy consumption (MV is the least efficient of the 4 light types).

Pursuant to the Energy Policy Act of 2005, Mercury Vapor lamps became obsolete due to their inefficient use of energy and inclusion of mercury as a component, and effective January 2008, were banned from production in the United States. At the end of 2007, MV's comprised almost 52% of DTE Electric's company owned lighting assets, and the balance consisted primarily of HPS lighting (a nominal number of lights were MH at the time). DTE Electric began to convert failed MV lighting to LED for E1 Option I customers starting in 2017 in accordance with the Commission's order on January 31, 2017, in Case No. U-18014.

The Company has worked closely with its municipal partners, commercial and residential customers over the past decade as they transition to LEDs as a preferred lighting technology. In 2022, the Southeast Michigan Council of Governments (SEMCOG) made available grant funding for several types of carbon reduction initiatives, which included municipal lighting conversions to LEDs. DTE made aware and assisted several communities to complete their applications. In 2023, almost $3.4M in grant funds were awarded to several DTE municipal customers to help fund HID to LED conversion projects totaling approximately 11,000 lights anticipated between 2024 – 2025. Table 2 below provides a snapshot of the changes over time in DTE Electric's company owned lights, from 2012 to 2023:

Table 2: Community Lighting Assets by Lighting Type (2012-2023)[2]

Lighting Type	2012	2017	2023
Light Emitting Diode (LED)	2,851 (1%)	53,018 (27%)	124,565 (62%)
High Presure Sodium (HPS)	98,070 (49%)	91,422 (46%)	53,374 (27%)
Mercury Vapor (MV)	94,681 (48%)	52,518 (26%)	19,895 (10%)
Metal Halide (MH)	2,977 (2%)	2,468 (1%)	1,622 (1%)
Total Assets	198,579	199,426	199,377

Q13. Can you provide an overview of the various lighting technologies employed within DTE's Municipal Street Lighting Business, E1 Option I?

A13. The current lighting portfolio for street lighting customers served on DTE Electric's E1 Option I Rate Schedule referenced in Table 1 above, includes approximately 166,000 total Company owned lights as of November 1st, 2023. Table 3 below shows the light type breakout by total count and percentage:

Table 3: E1 Option I Light Counts by Type

Lighting Type	Asset Count	% of Total Assets
Light Emitting Diode (LED)	113,584	69%
High Presure Sodium (HPS)	40,417	24%
Mercury Vapor (MV)	10,695	6%
Metal Halide (MH)	1,355	1%
Total E1 Option I Assets	166,051	100%

[2] Light counts as of November 1st, 2023.

While the quantity of high-pressure sodium and mercury vapor luminaires has been steadily dropping over the past several years, the total number of LED luminaires continues to increase in-kind due primarily to municipal driven conversions. Metal halide lighting luminaires represent approximately 1,400, or less than 1% of DTE Electric's company owned lighting luminaires. As noted earlier, more than 20% of the remaining non-LED municipal streetlights are targeted for conversion to LED as a result of the recently awarded SEMCOG project grants.

Q14. Can you provide an overview of the various lighting technologies for street lights that are municipality owned (E1 Options II & III)?

A14. The lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of 85 (71%) high pressure sodium lights and 34 (29%) mercury vapor lights. As previously indicated, this service has been closed to new customers since 2009, and existing E1 Option II Rate Schedule customers electing to convert to LED are required to convert to DTE Electric's E1 Option I or Option III Rate Schedules. The mix of lighting for DTE Electric's E1 Option III Rate Schedule includes approximately 70,000 (84%) LED luminaires, 12,000 (15%) high pressure sodium luminaires, and the remainder consisting of MV and MH lighting. The high concentration of energy-efficient LED lighting in this class reflects the City of Detroit's conversion of most of its streetlights to LED.

Q15. Can you provide an overview of DTE Electric's Community Lighting D9 OPL, E2 ATS, and E1.1 metered municipal-owned lights rate schedules?

A15. DTE Electric's D9 OPL rate schedule and its proposed pricing reflect recovery of costs associated with the ownership, maintenance, and provision of energy to a portfolio of approximately 24,000 commercial and 9,000 residential outdoor protective lights. OPL lighting uses the same technologies as streetlighting and, consistent with conversions of failed mercury vapor streetlights to LED, the Company began converting failed mercury vapor OPLs to LED starting in February 2017.

DTE Electric's E2 Rate Schedule and proposed pricing reflect the recovery of costs for the production and distribution of energy for automated traffic signal (ATS) lights owned and maintained by municipalities and other public authorities.
DTE Electric also provides metered, municipal-owned streetlight service under the E1.1 Rate Schedule. I support the energy forecast for this Rate Schedule and Witness Willis supports the proposed rate for this service.

Q16. Is DTE Electric proposing any changes with respect to the maintenance and installation of HPS lighting technology?

A16. Yes. In 2023, our key lighting vendors informed us that they will be or are considering phasing out their HPS product lines in 2024. Given the continued movement toward LED technology, we have decided to sunset our active maintenance and support for HPS fixtures effective the earlier of January 1st, 2025, or depletion of remaining HPS inventory. We have discontinued the purchase of all HPS stock effective November 2023.

Q17. Why has the Company decided to wait until 2025 to stop maintaining HPS fixtures?

A17. Similar to the approach taken by the U.S. Department of Energy (DOE) in its April 2022 announcement of the phaseout of most incandescent lightbulbs that went into effect mid-2023, we've elected to wait until 2025 to formally adopt this change. This will allow time to 1) inform our customers of this change in policy and address any concerns they may have, and 2) provide our customers time to socialize this change with stakeholders within their communities. Though there has been broad community support in the adoption of LED lighting technology, it is not unanimous. Therefore, the remaining inventory will be used to accommodate these requests in the short term and further support an orderly transition to LEDs. We will continue to maintain HPS lights as currently proscribed in the tariff throughout 2024 unless HPS stock has been depleted prior to 2025.

Q18. How is the Company proposing to manage replacement of HPS fixtures that require maintenance upon depletion of stock or after 2024?

A18. Similar to its policy for MV fixtures, DTE is proposing to maintain HPS fixtures through replacement upon failure with equivalent LED luminaires at no additional charge to the customer. In support of this transition, the Company has also decided to offer a HPS per light labor credit starting in 2024 for those municipalities that have decided to proactively convert to LEDs for which projects have not yet begun. The labor credit of $65 is the same as the MV labor credit applied to such conversions.

Q19. What steps has the Company taken to inform its' municipal customers of this change?

A19. In November of 2023, DTE notified all of its' municipal customers which continued to take service from HPS fixtures via email with an attached letter (Exhibit A-25 O3). This letter highlighted why the change was occurring, the transition period mentioned above, the benefits of LEDs, and lastly, the new labor credit being offered for HPS to LED conversions.

Q20. Are you proposing any changes to the E1 Option I and D9 tariff language?

A20. Yes. We are proposing to include the following language for both E1 Option I and D9 tariff options: "*Effective January 1st, 2025, new high pressure sodium (HPS) fixtures will no longer be available. Customers with existing HPS fixtures will continue to receive service until those fixtures fail. At that time, the fixture will be converted to an LED luminaire.*"

<u>**Community Lighting Sales Forecast**</u>

Q21. How did you develop the Lighting sales forecast for E1 Options I & II?

A21. Consistent with the methodology utilized in prior Company electric rate cases, the sales forecast for the E1 Option I & II Rate Schedules were developed by first preparing a forecast of light counts for each lighting type (technology and wattage size) for the projected test period based upon: (1) known projects, (2) continued conversions of mercury vapor lighting to LED lighting, and (3) an estimate of increased light counts net of removals, resulting from sales growth. The system wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting type was applied to the forecasted volume of lights for each lighting type. Annual usage was assumed to be 4,200 hours, to reflect the hours that the lights on either the dusk to dawn or standard provision are illuminated. The energy forecast for lights on the dusk to midnight provision was based upon 2,100 hours use and the energy forecast for lights on the de-energized provision is zero. Lastly, pursuant to the order in Case No. U-21297, we reduced the E1 Option I annual usage of 4,200 hours (dusk to dawn) and 2,100 hours (dusk to midnight) by 3.25% to account for lights that are non-operational throughout the course of the year. This adjustment is reflected within my workpapers titled "U-21534 Lighting Forecast" and "U-21534 Lighting Rate Model."

Q22. How did you develop the Lighting sales forecast for E1 Option III, D9, E2, and E1.1?

A22. The sales forecast for the E1 Option III Rate Schedule was developed by first preparing a forecast of light counts for each of the lighting types for the projected test period based upon known municipal-owned streetlighting projects and an estimate of light count changes. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which all the lights are illuminated on an annual basis.

The total sales forecast for the OPL D9 Rate Schedule was developed by preparing a forecast of light counts for each of the lighting types for the projected test period based upon existing light counts, an estimate of increased light counts resulting from sales growth net of removals, and continued conversions of mercury vapor lighting to LED lighting. The system wattage value applicable to each lighting type was applied to the forecasted volume of lights for each lighting type for the 4,200 hours for which the lights are illuminated on an annual basis.

The sales forecast for the E2 ATS Rate Schedule was determined by using the total connected wattage, as of November 2023, for the rate schedule and determining the annual usage based upon that determinant. In other words, it is simply the product of the total reported wattage and the total number of hours in the projected test period.

The total sales forecast for the E1.1 Rate Schedule was based upon annualized usage data for the 12-month period that ended June 2023.

Company Preventative Maintenance Programs

Q23. What preventative maintenance programs does the Company manage and how are the related expenses classified?

A23. The Company manages the following preventative maintenance programs: 1) Post Inspections, 2) Post Painting, 3) Night Patrol, 4) Post Replacement, and 5) Cable Replacement. The Post and Cable Replacement programs are considered capital expenditures while the remaining programs are booked as O&M.

Q24. Please describe the Company's Post Inspection program and its relationship to the Post Painting and Post Replacement programs.

A24. DTE Electric owns more than 60,000 decorative metal posts and has established detailed post inspection criteria to inspect its posts every three years to both identify posts whose structural integrity dictates their replacement (condemnation), and posts that require painting. At the time posts are inspected, minor post maintenance work such as adding or replacing post asset tags, post hand-hole covers, and T-box door covers may also be completed. Over the past three years, DTE Electric's decorative post inspection process has resulted in the annual replacement of condemned posts at a rate of approximately 3% and post painting at a rate of approximately 2% relative to the total population of posts.

Q25. Does the Company also inspect its streetlight-only wood poles?

A25. Yes. Our streetlight-only wood poles are inspected as part of DTE's pole top maintenance (PTM) program managed by Distribution Operations. As wood poles are inspected through this program, streetlight-only wood poles identified as condemned or near end-of-life, are sent to DTE – Community Lighting for replacement by its' contractor(s) responsible for replacing our decorative metal posts.

Q26. Please describe the Company's Night Patrol program and its purpose.

A26. To further bolster customer service and reliability, the Company implemented a Night Patrol program in 2019 with the intent to proactively identify municipal-wide outages which would then be routed to a DTE authorized construction crew for repair. All of DTE's E1 Option I streetlights are within the scope of this program, and depending on prior patrol results and repair detail (i.e. large percentage of outages noted in a single municipality or high concentration of outages in a specific area), the Company may adjust the timing of the next scheduled night patrol.

In 2022, DTE developed a night patrol database to record details by light and by circuit as to the nature and recurrence of outages. The purpose of cataloging this data is to allow the Company to utilize analytics to identify repeat visits to the same luminaire or problematic circuits because of underground cable failures.

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Q27. Why did the Company launch the Cable Replacement program which targets underground cable replacements?

A27. As more outage data continues to be collected from the Night Patrol program, we are beginning to identify root cause issues through direct feedback from our contractors tasked with restoring service, and data on specific lights and circuits that indicate recurring outages. In general, outages are the result of 1) a failed luminaire, 2) failed wiring or components such as a photocell, or 3) failed underground cable.

This program specifically targets underground cable replacement work as this tends to be the costliest type of repair to perform on a reactive basis and has a higher likelihood to impact multiple lights when the cable begins to fail. Repairing larger stretches of cable using a data driven approach on a planned basis through this program is not only more cost effective, but is also anticipated to reduce the likelihood of one or more lights failing due to an underground fault once replaced, thereby increasing reliability.

Q28. You mentioned that proactive underground cable replacement work is more cost effective than reactive repairs. Can you elaborate?

A28. When responding to outage events that involve underground cable failures as the root cause, our repair crew's primary objective is to address the immediate issue and restore service as quickly as possible. This increases the number of "locate and repairs" which result in sections of failed cable being isolated and replaced. Though this addresses the immediate root cause, it doesn't necessarily increase the longevity of the stretch of cable supporting that circuit, in a manner that replacing failed or end-of-life underground cable would.

Q29. Are there any other long-term benefits expected to be realized from the Cable Replacement program?

A29. Yes. First, most of the underground system cable that is currently in service is direct buried, meaning that the cable is unsleeved and buried at a depth which makes it more susceptible to freezing and thawing impacts as well as 3rd party strikes during excavation work (i.e. other utility work or municipal driven projects such as road widening). Cable that is replaced under this program is now installed within a protective sleeve which increases the likelihood that it can survive a 3rd party strike or become exposed through excavation. Second, as damaged and end-of-life cable is replaced with newly installed and protected cable, we expect to see a reduction in outages whose root cause is determined to be an underground cable failure. Over time, this will reduce the number of reactive underground cable events and increase lighting system reliability.

Outage Restoration Activities

Q30. What was DTE Electric's performance with respect to outage duration for its lighting customers?

A30. DTE Electric's 2022 performance was 4.2 calendar days. These historical metrics for outage duration and defects are displayed on Exhibit A-25, Schedule O1.

In addition to weather-related events, "long duration" and "follow-up" outage events include extended repair time for underground faults (i.e. Miss Dig permits), repairs resulting from third party damage, and lack of special order material (SOM) maintained by a city or municipality. The performance metrics only include reactive street light outage repairs; they do not include any outage repair resulting from patrol and fix activities. However, Exhibit A-25, Schedule O1 does reflect the total number of lights canvassed from the night patrol program as well as the number of outages identified from these patrols. Street light outage events reported on weekends and after normal week-day business hours are analyzed and dispatched to crews on the following business day. DTE Electric measures both total and crew duration cycle repair periods. Crews authorized by DTE Electric work to complete reactive outage repairs of reported street light outage events.

Q31. What other measures does DTE Electric have in place to improve its restoration time and to maintain a high level of customer service?

A31. Restoration performance, among other metrics, are reviewed with our contractors at monthly performance meetings and, to the extent that restoration performance is not meeting expectations, DTE Electric can shift restoration work as needed to alternate contractors to achieve the desired restoration performance. Internally, the Company evaluates contractor performance metrics on a weekly basis to identify potential performance issues or problem-solving opportunities. In addition to these efforts, the Company continues to improve the arrangements for the provision of special-order materials on behalf of municipalities that choose streetlight materials that are not included in DTE Electric's standard streetlight offerings.

Q32. Could you please summarize DTE's Outage Performance over the past six years?

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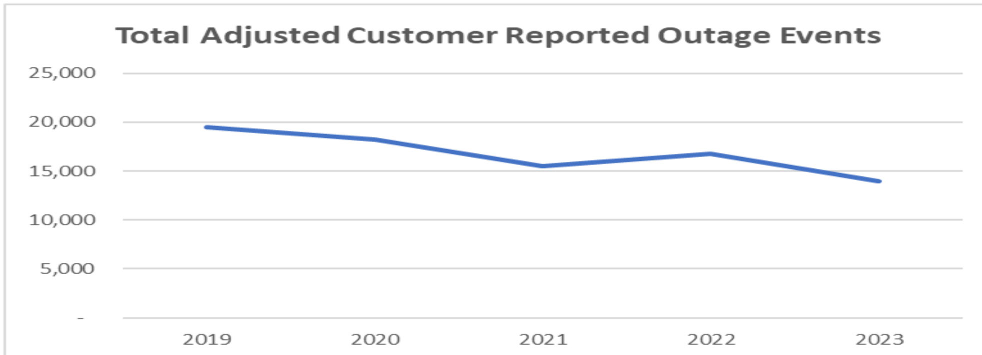
A32. While any individual year will be impacted by external factors such as changing weather patterns (i.e. more freezing and thawing leads to increased cable faults) and number of catastrophic storms (i.e. construction crews being diverted to assist in power restoration activities), key outage metrics continue to trend in a positive direction when evaluating performance collectively, over the past six years. Specifically, the outage data summarized in Exhibit A-25, Schedule O1 indicates a positive impact in terms of the correlation between our proactive efforts resulting from the night patrol & underground cable replacement programs to reduce customer reported outage events (when adjusting for the removal of "ok on arrivals" and "streetlight knockdowns" and adding "follow-up events completed) from approximately 19,500 in 2019 to approximately 14,000 in 2023 as Chart 1 below illustrates:

Chart 1: Total Adjusted Customer Reported Outage Events



As we collect more night patrol data, we will continue to use this data to strategically target municipalities based on historical results.

Q33. Were there any requirements as part of the order in Case No. U-21297 pertaining to DTE making streetlighting outage reports available to municipalities that request them?

A33. Yes. Specifically, the Order on page 373 states "…DTE Electric Company shall work with interested stakeholders to develop a streamlined streetlight outage report request process, a standard report request process, a standardized report format, data protocols, and delivery method and shall update its E1 tariff to reflect the following:

> *Any E1 streetlight customer may request to receive from the company a calendar-year report, to be delivered by the company on or before February 28 of the following year, providing, at a minimum, streetlight outage occurrence counts, average outage durations and counts of outages lasting longer than 14 days, covering all E1 streetlights served under all of the customer's accounts. Customers with more than 5,000 E1 streetlights, may request to receive quarterly reports containing the same information, to be delivered by the company within two months of the end of each calendar quarter."*

Q34. What modifications are you proposing to the tariff language as provided in the Order?

A34. We propose clarifying that outage reporting will only be available for E1 Option I customers, as these are the only streetlights within E1 that the Company owns, operates, and maintains.

Q35. When do you anticipate implementing this new process and making this outage report available to requesting municipalities?

A35. We have been working toward developing an outage report for municipalities that includes 1) streetlight outage occurrence counts, 2) average outage durations, and 3) counts of outages lasting longer than 14 days. A meeting with MPSC Staff, MAUI, and other interested stakeholders is scheduled end-March 2024 to share our proposed reporting template which provides the outage data required by the order in Case No. U-21297. Our goal is to collectively agree upon the reporting framework, content, delivery, and effective date for implementation. Our new reporting system discussed below, will help to streamline the process of preparing the outage reports once the system has been tested and debugged.

Q36. Can you provide an overview of the Company's new outage management system?

A36. In late 2023, Community Lighting began its transition to a standalone outage management system (OMS), KloudGin. Initially part of the Advanced Distribution Management System (ADMS) solution, this standalone OMS system will enable us to issue outage work to our contractors more efficiently, increase our ability to remove duplicate events (i.e. same outage reported by multiple parties), and when

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fully functional, allow for enhanced automation for outage reporting by municipality.

Q37. What is the status of the new OMS system and when do you expect it to be fully functional?

A37. The remaining work of integrating this OMS system into our operations is expected to be completed by the end of Q1 2024. Once completed, our group will need to work with our IT group and the software vendor to stress test this software to identify and correct errors and issues. We are tentatively aiming to have the software being fully functional by Q2 or Q3 2024. Once fully operational, our goal for this system to be able to automate the outage reporting by municipality in compliance with the Case No. U-21297 order.

Q38. What was Community Lighting's spend with respect to outage restoration activity?

A38. In 2022, DTE Electric's Community Lighting team spent approximately $8.1 million on outage restoration expense with approximately 76% of this cost being capitalized, and the balance being recorded as O&M. The outage restoration expense was approximately $7.6 million in 2021. Exhibit A-25, Schedule O2 reflects DTE Electric's historical performance for outage restoration cost per event.

Q39. Please explain the difference between capitalized outage expenses and non-capitalized, or O&M outage expenses.

A39. Outage restoration activities include remediating identified lighting outages that could range from replacement of small wiring or lighting components to replacement of system cable, posts, and luminaires. Any repair (inclusive of both materials and labor) that does not extend the useful life of the lighting asset (small wiring or lighting components such as a replacement of a fuse) is considered an O&M expense. All other repairs (both materials and labor) are considered capital expenditures.

Community Lighting Operations & Maintenance and Capital Expenditures

Q40. What is included in the Operations & Maintenance of Street Lighting and Signal Systems account on line 23 of Exhibit A-13, Schedule C5.6, page 1?

A40. Line 23 on this exhibit shows the projected O&M expenses which are directly assigned to Account 596, Maintenance of Street Lighting and Signal Systems. This account represents preventive maintenance expense, labor expense and non-capitalized outage restoration expense. The preventive maintenance work includes post inspection, post painting, and night patrols for DTE owned municipal streetlights. The labor expense primarily reflects the labor of the Community Lighting team including sales, planning, asset maintenance, construction, and asset engineering. As reflected on Exhibit A-13, Schedule C5.6, the historical period O&M expense of $4.0 million is adjusted first for normalization attributable to an anticipated reduction in O&M related outage spend of $0.25 million, and then for inflation of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025. This results in a forecasted O&M expense of $4.1 million in the projected test period.

Q41. What are the Community Lighting capital expenditures on Exhibit A-12, Schedule B5.5, "Projected Capital Expenditures – Community Lighting"?

A41. Capital expenditures for Community Lighting for 2022 were $17.8 million. The 2022 expenditures included approximately $6.3 million for new installations and replacements, $7.4 million for outage restoration, $1.7 million for cable replacements, $1.5 million for post replacements, and $0.9 million for planned HID to LED conversions.

The projected capital expenditures for Community Lighting are $16.7 million for 2023, $16.7 million for 12 months ending December 31, 2024, and $17.3 million for 12 months ending December 31, 2025. Similar to the 2022 actual expenditures, these projections include outage restoration, including conversion of failed mercury vapor luminaires to LED for both streetlight and OPLs, post replacement, new business, and capital support staff. As previously discussed, Community Lighting launched its underground cable replacement program in 2022 which is also included in Exhibit A-12, Schedule B5.5 line 4 with projected spend of $1.5 million for 2023, $1.1 million for 12 months ending December 31, 2024, and $1.7 million for 12 months ending December 31, 2025.

<u>LED Luminaire Selection Methodology Specific to HID to LED Conversions</u>

Q42. Can you provide an overview on HID to LED conversions and DTE's LED selection methodology for such conversions?

A42. In Case No. U-21297, we described two distinct scenarios in which the Company recommends installation of specific LED luminaires, and our LED selection methodology for both. The first scenario pertains to new lighting installations. A new installation for purpose of this discussion, is generally defined as installing poles, wiring, and luminaires where they did not exist previously (i.e., a municipality has constructed a roundabout and engaged DTE to provide a lighting design for the new roundabout). In this scenario, all new lighting installations will be evaluated in accordance with ANSI/IES RP-8 standards.

The second scenario, which results in the majority of LEDs being installed, pertains to HID to LED conversions on pre-existing lighting systems. Most lighting systems that the Company owns, operates, and maintains, were installed decades ago, and pre-date current lighting standards that the Company adheres to today when making recommendations for new lighting installations. As stated in my rebuttal testimony in Case No. U-21297, "[t]he Company understands that pre-existing streetlighting infrastructure may not meet ANSI/IES RP-8 standards, and that it would be impractical and costly for municipalities to do so."[3] The reason it would be impractical and costly to conform to current ANSI/IES RP8 lighting standards for pre-existing lighting systems is that these older municipal lighting systems would need extensive reconfiguration inclusive of work such as pole relocations and rewiring of the overhead and underground system cable. Therefore, our objective during conversion work is to restore the equivalent "out of the box" initial output of the HID luminaire with an LED luminaire.

Under either scenario, the customer has the choice to deviate from the Company's recommended lighting design.

Q43. Could you please summarize the order in Case No. U-21297 with respect to the Company's LED selection methodology?

[3] Bellini Rebuttal Testimony, Case No. U-21297, pg. 12, lines 21-23

A43. The MPSC Commission in their order in Case No. U-21297 disallowed approximately $5.8M of LED plant from the Company's historical books, determining that the Company had overspent on LED conversions, in part based on the wattage of the luminaires it selected as compared to a crossover chart from the Company's primary LED lighting vendor, Leotek.

Specifically, on page 137 of the order, the Commission states "…DTE Electric does not deny that its lamp choices exceed what Leotek recommends as a high-level choice. The ALJ further found that "DTE has not established that it has any meaningful discussion[4] with customers currently regarding the choice of lighting" and that "since DTE does not conduct any analysis of the appropriate lighting for the roadway at issue, it is difficult to credit that DTE meaningfully consults with its municipal customers." Absent convincing evidence to the contrary, the ALJ found that the crossover recommendations are reasonable."

Q44. What significant developments have occurred since the order in Case No. U-21297?

A44. Specifically, Leotek no longer supports their crossover chart and has removed them from their Company's website. This Leotek crossover chart was one of the primary reasons for the MAUI adopted proposal of DTE's historical LED plant reductions as reflected in witness Bunch's workpaper prepared in Case No. U-21297, included here as Exhibit A-25 Schedule O4 titled "WP Calculation of $5.8M Disallowance by MI-MAUI in U-21297."

[4] U-21297 Proposal For Decision, p. 340.

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Q45. Are you recommending that the MPSC Commission revisit the reasoning that resulted in the disallowance of the LED plant-in-service in Case No. U-21297?

A45. Yes. Both DTE and MAUI drew distinctly different conclusions from the Leotek crossover chart presented in Case No. U-21297. Given that the crossover chart is no longer supported by Leotek, which was the primary evidence used to determine the excessive spend in LEDs during conversions, it would be prudent to revisit the methodology employed by DTE in its HID to LED conversions on pre-existing streetlighting systems.

In the instant case, DTE sought the opinions of two lighting industry experts (discussed later in my testimony) to review and provide independent opinions as to the reasonableness and prudency of DTE's LED selection methodology as it relates to conversions. Given the technical complexity of this topic and the limited time available to discuss this issue in the context of a rate case, the Company would be amenable to a Staff facilitated technical workshop inclusive of Leotek's engineering team, DTE, expert consultants, and MI-MAUI with the intent of evaluating appropriate HID to LED equivalent conversions employed by DTE and determine whether or not DTE unnecessarily installed more expensive LEDs during conversions. It would also be prudent to directly engage with Leotek and the preparer of this chart in order to assess whether or not DTE erred in selecting luminaires that deviated from this chart which is no longer supported by Leotek.

Q46. Is DTE presenting additional evidence supporting its' selection methodology specific to HID to LED conversion projects on pre-existing lighting systems?

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A46. DTE has sought the independent review and opinions of two lighting industry experts, Dr. Ronald Gibbons, PH.D., FIES, currently the Director of the Center for Infrastructure Based Safety Systems (CIBSS) at the Virginia Tech Transportation Institute (VTTI)[5], and Donald McLean, PLEng (Founder and Senior Partner, DMD Consulting Engineers, Ltd)[6] as to the appropriateness of DTE's LED selection methodologies pertaining to HID to LED conversions. Both experts were asked to review and opine on DTE's lighting study which recommended 58W and 136W LED selections when converting 100W HPS and 250W HPS fixtures, respectively, as these HPS fixture types are the most commonly converted municipal fixtures.

Q47. Please summarize <u>Don McLean's</u> findings and overall conclusion with respect to DTE's LED selection process when converting HID's.

A47. Mr. McLean's key points from his conclusion detailed in his report (Exhibit A-25, Schedule O5, page 15) are quoted below:

- "From a comparison standpoint, matching published lumens from luminaire to luminaire is not always the best method. It is more important to assess lighting levels on the roadway, which was undertaken by DTE."
- "DTE reviewed both roadway lighting levels on and off the roadway defining lighting Luminance and Illuminance metrics in the analysis, including spill lighting. In our opinion, what DTE have provided is reasonable for an HPS to LED conversion given they have focused on calculated lighting levels on the roadway vs simply using lumen values."

[5] U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, p12 - 28
[6] U-21534 Exhibit A-25 Schedule O8_Don McLean_Curriculum Vitae

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- "DTE's use of multiple roadway types and averaging the results of these roadways is a reasonable methodology to use in comparing luminaires and as a luminaire selection guide in large scale retrofit HPS-LED conversions."
- "Based on the criteria and approach defined by DTE, DMD is in agreement with the conversion methods and LED luminaires chosen to replace the incumbent 100W and 250W HPS luminaires."

Q48. Please also summarize <u>Dr. Gibbons'</u> findings and overall conclusion with respect to DTE's LED selection process when converting HID's.

A48. Dr. Gibbons' key points from his conclusion detailed in his report (Exhibit A-25, Schedule O9, page 11) are quoted below:

- "The approach DTE Energy used for the selection of luminaires is valid and aligns with the state of the art in the industry."
- "The luminaires selected by DTE energy were appropriate for the template roadways considered in their analysis."
- "The appropriate luminaires for intersection evaluations selected through analysis are Leotek 136W and the Leotek 58W for the 250Watt HPS and for the 100 Watt HPS respectively."

Q49. Please identify and define the primary LED lighting criteria evaluated by DTE when selecting an appropriate LED replacement of an HID light.

A49. Though there are several criteria used in evaluating lighting options, roadway illuminance and luminance are weighted more heavily than other criteria such as glare, light trespass, etc.

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The Texas Department of Transportation (TxDOT) provides the following simple definitions for roadway illuminance and luminance:[7]

- Roadway Illuminance: Measurement of the amount of light that hits the pavement surface.
- Roadway Luminance: Measurement of the reflected light from the pavement surface that is visible to the motorist's eye.

TxDOT states that "[t]he level and uniformity of illuminance or luminance along a highway depends on several factors, including the lumen output of the light source, luminaire distribution, mounting height, luminaire position, pavement reflectance, and pole spacing and arrangement."

This weighting criteria is consistent in both the manner in which DTE assessed proper LED selections when converting municipal HID lighting projects and also as evaluated by both industry experts discussed in their detailed findings below.

Q50. Please briefly explain the parameters of the reviews conducted by both experts.

A50. Both Don McLean and Dr. Gibbons conducted an independent review based on information sourced and used by DTE in its' own analysis ("WP-RAB – Work Paper A – Agi 32 Simulation Files_100W HPS" through "WP-RAB – Work Paper Q – IES Photometric Files_LED") in selecting LEDs used in HID to LED conversion projects.

[7] Highway Illumination Manual: Illumination Levels (txdot.gov) available at https://onlinemanuals.txdot.gov/TxDOTOnlineManuals/TxDOTManuals/hwi/illumination_levels.htm#i1024407

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Both reviews were specific to DTE's most commonly converted fixtures, the 100W and 250W HPS fixtures. Both compared new (or "out of the box") LED luminaires to new HPS luminaires.

Q51. Please highlight <u>Mr. McLean's</u> review process and specific conclusions from his report (Exhibit A-25, Schedule O8) on DTE's selections of the 58W and 136W to replace 100W and 250W HPS fixtures, respectively.

A51. The key findings are noted below in various quoted excerpts from Mr. McLean's report (Exhibit A-25 O5 "Don McLean DTE HID-LED Selection Methodology Opinion Letter"):

<u>100W HPS Replacement Evaluation</u>

"Revised Rdwy Performance Summary.xlsx (Exhibit A-25 O7_DMD_Rdwy Performance Summary) contains Target Roadway lighting calculation summaries for Roadways 100A through 100G as provided in "Workpaper G - Roadway Typicals Master Table 02 01 18." These 7 roadways pertain to 100W HPS replacements only. The calculation summaries contain roadway Luminance and Illuminance metrics for the existing 100W HPS and the 4 LED luminaires DTE used in the conversion analysis."

"Revised Rdwy Performance Summary.xlsx" then takes the calculation summaries for each of the 4 LED models considered in the analysis and compares the average values for Luminance and Illuminance to the average values for the HPS luminaire as HPS is taken as the baseline."

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250W HPS Replacement Evaluation

"Revised Rdwy Performance Summary.xlsx" contains Roadway lighting calculation summaries for Roadways 250A, 250B, 250C AND 250F as they are described in the Exhibit G - Roadway Typicals Master Table 02 01 18 (Rate Case) (Master Tables). These roadways pertain to 250W HPS replacements only. The calculation summaries contain roadway Luminance and Illuminance metrics for the existing 250W HPS and the 4 LED luminaires used in the analysis."

"Revised Rdwy Performance Summary.xlsx" then takes the calculation summaries for each of the 4 LED models considered in the analysis and compares the average values for Luminance and Illuminance to the Average values for the HPS luminaire as HPS is taken as the baseline."

58W LED Results Summary

"The light levels produced by the 58W LED Luminaire showed an increase in Average Illuminance. The 58W fixture failed to meet spill light targets at surrounding property lines with a 51.2% increase compared to the 100W HPS baseline. While the 37W, 30W and 27W fixtures meet spill lighting targets within a reasonable tolerance, the 58W luminaire is the only fixture that was able to maintain the minimum Average Illuminance of the HPS baseline."

136W LED Results Summary

"The 136W luminaire had the highest Average Illuminance out of the 4 LEDs at only 3.5% below the target HPS baseline levels, which we would deem to be within a reasonable level of tolerance. The 136W LED luminaire was also the only luminaire to maintain baseline spill light levels, with a 27.3% reduction in max spill light levels at property frontages compared to the 250W HPS baseline."

Q52. Please highlight <u>Dr. Gibbons'</u> review process and specific conclusions from his report (Exhibit A-25, Schedule O9) on DTE's selections of the 58W and 136W to replace 100W and 250W HPS fixtures.

A52. In Dr. Gibbons review of various simulations, he "verified the parameters placed in the simulation including luminaire type, location, and tilt angle" and then "calculated the lighting levels within each model." Using this data, Dr. Gibbons then "compared the calculated results to the incumbent HPS technology where the roadway illuminance, luminance, glare, sidewalk illuminance and light trespass values were reviewed. In the analysis, the result criteria were established that the luminaire had to increase the luminance and illuminance on the roadway with the desire to increase the sidewalk illuminance, while reducing glare and light trespass."[8] The key findings are noted below in various quoted excerpts from Dr. Gibbons report ("Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV):"

<u>100W HPS & 250W HPS Replacement Evaluation</u>

"In the review of the DTE methodology, I [Dr. Gibbons] opened the AGI32 Simulation packages for the 100 Watt HPS replacement comparisons and the 250 Watt HPS comparisons. In all there were 8 comparison templates for 100 Watt selection process and 4 templates for the 250 Watt comparisons. In each of the simulations, I verified the parameters placed in the simulation including luminaire type, location, and tilt angle. I

[8] U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, p3-4

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then calculated the lighting levels within each model. Using this data, I compared the calculated results to the incumbent HPS technology where the roadway illuminance, luminance, glare, sidewalk illuminance and light trespass values were reviewed. In the analysis, the result criteria were established that the luminaire had to increase the luminance and the illuminance on the roadway with the desire to increase the sidewalk illuminance while reducing glare and the light trespass."

58W & 136W LED Results Summary

"Based on this analysis, I [Dr. Gibbons] would recommend the Leotek 58W to replace the 100W HPS and the Leotek 136W to replace the 250W HPS."

LED Comparison Matrices Summarizing Dr. Gibbons findings[9]

Table 4: Study Results of 100W HPS to LED Conversion for Continuous Lighting on Straight Roadway

	LED 58W	LED 37W	LED 30W	LED 27W
Roadway Template A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template B	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template D	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template E	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template F	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template G	Fully Meets	Fully Meets	Fully Meets	Does not Meet

	Roadway Descriptions
Roadway Template A	2013 Application Specification (one row, near side, 2-lanes, 24' road width, 28.5' MH, 2' setback, 150' pole-to-pole spacing)
Roadway Template B	Greenbush Rd, Wayne
Roadway Template C	Same as Roadway Template B with short arm application change
Roadway Template D	15899 E. Eleven Mile Rd, Roseville
Roadway Template E	16461 E. Eleven Mile Rd, Roseville
Roadway Template F	321 E. Granet Ave, Hazel Park
Roadway Template G	Same as Roadway Template F with short arm application change

[9] Summary of results prepared by DTE based on Dr. Gibbons analysis from tables presented in U-21534 Exhibit A-25 Schedule O9_Gibbons – DTE Energy Response Document & CV, pp 4-5, 11

Table 5: Study Results of 100W HPS to LED Conversion for Local/Local Intersection

	LED 58W	LED 37W	LED 30W	LED 27W
Local/Local A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local B	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Local/Local A	S. Linville Ave and Hazelwood St, Westland			
Local/Local B	Griffith Ave and Wiltshire Rd, Berkley			
Local/Local C	Pine St and 8th St, Port Huron			

Table 6: Study Results of 250W HPS to LED Conversion for Continuous Lighting on Straight Roadway

	LED 136W	LED 111W	LED 89W	LED 72W
Roadway Template A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template B	Does not Meet	Fully Meets	Does not Meet	Does not Meet
Roadway Template C	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template F	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Roadway Template A	2013 Application Specification (two rows, opposite, 4-lanes, 48' road width, 30' MH, 2' setback, 180' pole-to-pole spacing)			
Roadway Template B	Avondale St and Carlson St, Westland			
Roadway Template C	Same as Roadway Template B with short arm application change			
Roadway Template F	Ryan Rd between Mckinley Ave and Frazho Rd, Warren			

Table 7: Study Results of 250W HPS to LED Conversion for Local/Local Intersection

	LED 136W	LED 111W	LED 89W	LED 72W
Collector/Collector A	Fully Meets	Does not Meet	Does not Meet	Does not Meet
Collector/Collector B	Fully Meets	Fully Meets	Does not Meet	Does not Meet
Collector/Collector C	Does not Meet	Does not Meet	Does not Meet	Does not Meet
Collector/Collector A	Sheldon Rd and Saltz Rd, Canton			
Collector/Collector B	Avondale Rd and Wildwood Ave, Westland			
Collector/Collector C	13th St and Court St, Port Huron			

Q53. Please summarize DTE's four recommendations to the MPSC Commission based on the new evidence provided in the instant case.

A53. Recommendation 1: Based on both experts' independent analysis and conclusions as to the appropriateness of our LED selections for conversions, the Company

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believes it would prudent to continue utilizing 58W and 136W Leotek LEDs when converting 100W and 250W HPS luminaires, rather than being limited to the choices based solely on Leotek's crossover chart, which is no longer supported by the Company.

Recommendation 2: In addressing the ALJ's comments provided in the PFD in Case No. U-21297 (PFD, p. 340) that "DTE has not established that it has any meaningful discussion with customers currently regarding the choice of lighting," the Company proposes to memorialize our LED recommendations (noted in the preceding paragraph) to the customer in their contract prior to signing, and explicitly informing the customer in the contract and during discussions that the customer has the choice to select another LED at their discretion and confirmed in the municipal conversion agreement.

Recommendation 3: If the Commission deems it necessary, the Company would be amenable to a Staff facilitated technical workshop inclusive of Leotek's engineering team, DTE, outside consultants, and MI-MAUI with the intent of evaluating appropriate HID to LED equivalent conversions employed by DTE and also determining whether or not DTE unnecessarily installed more expensive LEDs during conversions.

Recommendation 4: Based on the new evidence presented by the Company in the instant case, we believe it may be appropriate to revisit the decision to disallow the \$5.8M in LED gross plant as ordered in Case No. U-21297.

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Community Lighting Rate Design

Q54. What does Exhibit A-16, Schedule F3 show?

A54. This exhibit shows the present and proposed rate design and corresponding revenues by rate schedule, based on the billing determinants for the 12 months ending December 31, 2025. The exhibit details the forecasted billing determinants as well as the resulting present and proposed rates and revenues. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The forecasted billing determinants were developed based on historical data and relationships, as well as known and measurable changes, and are consistent with the sales forecast as presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E1, Other class sales. The existing luminaire and energy rates, both non-capacity energy and capacity energy, as approved in the Order dated December 1, 2023, in Case No. U-21297 are in columns (c), (d) and (e), and are used to calculate the present revenues in column (f). The luminaire rates proposed in this proceeding based upon the lighting cost of service (as discussed in detail below) are in column (g), the proposed non-capacity energy rates are in column (h), the proposed capacity energy rates are in column (i) and the resulting revenues from the new lighting cost of service are in column (j).

Q55. How were DTE Electric's present Municipal Street Lighting and Outdoor Protective Lighting charges determined?

A55. The lighting rates approved in MPSC Case No. U-21297 reflect a monthly energy charge, both non-capacity energy and capacity energy, and a luminaire charge. The monthly energy charge was determined by applying the energy rates, both in cent/kWh, to the calculated consumption values of the various lighting technology lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge is a fixed monthly amount applied to each luminaire dependent on the technology utilized, the lamp size or wattage, the lighting provision and whether it is served from underground or overhead. The total (energy and luminaire) monthly lighting charges that were calculated in Case No. U-21297 do not fully represent true cost of service rates by technology type (within the lighting rate class). In Case No. U-21297, the lighting rates were gradually moved towards cost of service, with the total movement capped to minimize the impact on any individual customer.

Q56. What is the allocation methodology for production and distribution revenue requirements to the various lighting rate schedules that you are supporting in this case?

A56. The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non-capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the production revenue requirement for each rate class is capacity and non-capacity related, was used to allocate the production revenue requirement between the capacity and non-capacity energy charges. The E1 and D9 Rate Schedule energy charges, both capacity and non-capacity, were developed based upon the total production revenue requirement prepared by Witness Maroun for the E1 and D9 Rate Schedules.

Rate Schedule E1

Q57. How were the proposed E1 Rate Schedule luminaire charges determined?

A57. The Company determined the new luminaire service cost structures listed in the E1 Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3 by reviewing and allocating the specific cost of service components to the type of service, underground or overhead, and then further allocating them to the individual lighting technologies. There were no changes in the methodology for the allocation of non-production O&M costs or capital-related costs to luminaire charges proposed in this proceeding.

Q58. How was O&M allocated to the proposed E1 Rate Schedule luminaire charges in the lighting model?

A58. Total Distribution O&M expense reflected in the E1 Rate Schedule luminaire charge is $9.5 million, based upon the Company's cost of service model sponsored by Witness Maroun. This distribution O&M expense is comprised $3.2 million directly assigned to lighting and recorded in account 596 (Street Lights & OPL), $3.5 million allocated to lighting from various distribution operation and distribution maintenance accounts, $1.3 million from various customer service/sales accounts allocated to E1 Rate Schedule lighting and $1.5 million of total A&G expense. Based upon the underlying labor costs within account 596 and the various distribution operation, distribution maintenance and customer service accounts allocated to E1 Rate Schedule lighting, approximately 41%, or $0.6

million, of A&G expense was directly allocated to E1 Option I Rate Schedule lighting and the balance was allocated to the various distribution O&M accounts within the E1 Rate Schedule.

The total customer service and distribution O&M expense allocated to lighting, including A&G allocated to these accounts, was further allocated to the various E1 Rate Schedule luminaire/distribution charges based upon the system wattage of the luminaires and lamps. With the exception of post inspection, night patrols and post painting, all O&M ($3.2 million) and A&G ($0.6 million) directly assigned to lighting was spread equally across all luminaires. The O&M associated with post inspection and post painting was spread equally to all underground fed luminaires.

Q59. How was depreciation expense allocated to the proposed E1 Option I Rate Schedule luminaire charges in the lighting model?

A59. The total depreciation expense reflected in the E1 Option I Rate Schedule luminaire charges, as established in the Company's cost of service model supported by Witness Maroun, is $27.6 million. This reflects $20.3 million depreciation for the directly assigned lighting asset accounts, $3.1 million for the distribution asset accounts allocated to lighting, and the balance associated with general and intangible plant accounts allocated to lighting.

The depreciation expense for overhead subaccount 373.01 (street lighting and signal systems - overhead) was allocated directly to overhead fed luminaires, and depreciation expense for underground subaccount 373.02 (street lighting and signal systems – underground) was allocated directly to underground fed luminaires. The depreciation expense for overhead subaccount 373.03 (Street Lighting wire - OH) was allocated to all overhead luminaires equally. The depreciation expense for underground subaccount 373.04 (Street Lighting Wire/Cable - Underground) was allocated to all underground-fed luminaires equally.

The depreciation expense for both the overhead and underground luminaire subaccounts (LED Overhead, LED Underground, and HID Overhead, HID Underground) was allocated to the respective overhead and underground luminaires based upon lighting technology, wattage and underlying original investment. For instance, all underground-fed mercury vapor luminaires received an allocation of depreciation expense from subaccount 373.05 (Street Lighting Luminaires – HID Underground) based upon the luminaire type's investment and underlying mercury vapor luminaire useful life.

The depreciation expense that was allocated to lighting from distribution was allocated to all underground and overhead lighting based upon each luminaire type's system wattage -- the best representation of each lighting type's usage of the distribution system.

Q60. How was the revenue requirement for other taxes, return on investment and income tax allocated to the proposed E1 Option I Rate Schedule luminaire charges?

A60. All other components were allocated to the various luminaire types in a manner similar to that employed for the related underlying depreciation expense. For the directly assigned street lighting asset subaccounts, other taxes, return on investment and income tax followed the allocation of net plant to each of the lighting types.

Q61. Do you believe the proposed allocation of costs reflected in the various E1 Option I Rate Schedule luminaire charges is reasonable?

A61. Yes. The methodology utilized in the lighting model to allocate each of the individual cost of service components discretely, rather than in total, more accurately reflects the cost to provide lighting service to underground and overhead assets as well as the various lighting technologies. The use of the eight separate asset subaccounts for allocation of the capital-related costs results in more accurate rate setting based upon both how the lights are fed as well as the lighting technology, wattage and luminaire investment.

Q62. How were the E1 Option II Rate Schedule charges developed?

A62. The E1 Option II Rate Schedule charges were developed based upon a share of the production revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule, a share of the distribution and customer service revenue requirements allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule and a small allocation of the O&M expense directly assigned to the E1 Rate Schedule from Account 596. The allocations of revenue requirement from production, distribution and customer service to the E1 Option II Rate Schedule were accomplished on a per kWh basis across all E1 Option II rates. The proposed rates for the E1 Option II Rate Schedule are displayed in a luminaire charge, similar to that for Rate Schedule E1 Option I, and energy charges, both capacity and non-capacity, in a cent/kWh format.

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Q63. How were the E1 Option III Rate Schedule charges developed?

A63. The E1 Option III Rate Schedule charges were developed based upon a share of the total production revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule, a share of the total distribution revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule and a share of the customer service revenue requirement allocated by Witness Maroun in the Company's cost of service model to the E1 Rate Schedule. The allocations of revenue requirement from production, distribution and customer service to the E1 Option III Rate Schedule were performed on an equal energy basis across all E1 Option III rates. The proposed E1 Option III Rate Schedule distribution and energy charges, both capacity and non-capacity, are displayed in a cent per kWh format, allowing for a transparent comparison of lighting costs for the various luminaire system wattages and the various lighting technologies.

Q64. How does your proposed cost allocation methodology impact the present rates for the E1 Rate Schedule?

A64. The cost allocation methodology described above and employed in the lighting model reflects a collective revenue deficiency for the E1 Rate Schedule options.

Q65. What is your proposal regarding rate design in this proceeding for Rate Schedule E1 Option I rates?

A65. I have proposed a continuation of the gradual move towards rates which are entirely based upon cost of service for the lighting class. Consensus on this methodology was reached in the lighting collaborative ordered in Case No. U-17767 and

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beginning with rate Case No. U-18014, the Rate Schedule E1 Option I lighting rates are being gradually moved to rates which are entirely based upon cost of service.

Q66. How were the Rate Schedule E1 Option I proposed rates developed in this proceeding?

A66. The proposed Rate Schedule E1 Option I lighting rates were designed with two goals in mind; (1) continue the gradual move to rates which are entirely cost based and (2) minimize the impact of the proposed lighting rates on the monthly lighting bill for any municipality. Using the lighting rate model, the first step towards achievement of these goals was to limit the overall increase on any municipality and/or total lighting rate to 1.5 times the proposed average increase in revenue requirement. The second step of the process was to allocate the remaining revenue deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all the remaining lights.

<u>Rate Schedule D9</u>

Q67. How were the proposed rates for the D9 Rate Schedule determined?

A67. The proposed luminaire rates for the D9 Rate Schedule for both commercial and residential OPL service were developed based upon the allocated and directly assigned distribution costs supported by Witness Maroun in the Company's cost of service model. The luminaire rate design methodology employed in the lighting model for the D9 Rate Schedule mirrors the methodology employed for the E1 Rate Schedule with all allocated distribution costs assigned to luminaire charges based upon energy consumption and the directly assigned costs allocated based upon the underlying individual cost of service components. As I discussed earlier, the proposed energy charges, both capacity and non-capacity, for the D9 Rate Schedule for both commercial and residential OPL service were developed collectively with the E1 Rate Schedule energy charges.

Q68. Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-based?

A68. No. The proposed rates for Rate Schedule D9 required the use of the same two-step methodology to gradually achieve cost-based intra-class rates that was employed for the E1 Option I Rate Schedule.

<u>Rate Schedule E2</u>

Q69. How were the proposed Rate Schedule E2 charges determined?

A69. The Rate Schedule E2 charges were developed based upon the production, both capacity and non-capacity, and distribution revenue requirements allocated to Rate Schedule E2 customers by Witness Maroun in the Company's cost of service model. Each of the revenue requirement amounts were divided by the total forecasted energy for the projected test period to arrive at a distribution rate, a non-capacity energy rate and a capacity energy rate in cents/kWh.

Q70. How has Witness Maroun's presentation of the revenue deficiency for production presented in this case impacted your rate design?

A70. To allocate the targets to the lighting tariff energy charges, both capacity and non-capacity, in the cost of service-based rate presentation, I have allocated the revenue deficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the total D9 deficiency, and total E1 deficiency Rate Schedules to those energy rates in total.

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Q71. Will you please describe Exhibit A-16, Schedule F8?

A71. This exhibit contains the proposed tariff sheet changes which result from the pricing changes described above.

Q72. Does this complete your direct testimony?

A72. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PINA BENNETT

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF PINA BENNETT

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Pina Bennett (she/her/hers). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company ("DTE Electric" or "Company").

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Gujarat University (India) with a Bachelor of Science Degree in Electronics. In addition, I received a master's degree in business administration from Gujarat University in India. I have also completed several Company-sponsored courses and attended various seminars and conferences to further my professional development.

Q4. Do you have any professional certifications or other certifications?

A4. Yes, I also hold a Lean Six Sigma Black Belt certification.

Q5. Please summarize your professional experience.

A5. I began my career in India on the product management team at Torrel Cosmetics, a division of Torrent Pharmaceuticals, where I was responsible for launching a range of eleven skincare products. I worked in the business-to-business marketing industry in Singapore and was a professor at S. K. Patel Institute of Management & Computer Studies, teaching master's level marketing courses. While there, I developed an executive marketing training program for corporate executives. I joined DTE Electric in 2008 as the program owner for the Outdoor Protective Lighting program, in the Community Lighting organization, which was part of the DTE Electric Regulated Marketing organization. Between 2010 and 2018, I held a number of Chief of Staff positions across DTE Electric and DTE Energy Corporate Services (LLC). These positions had varying titles and supported the Vice President of Marketing, Vice President of Distribution Operations, Senior Vice President of Distribution Operations, Chief Administrative Officer, and Chief Nuclear Officer. In these roles, I was responsible for providing strategic oversight and organizational accountability for business success. I then became the Manager of Joint Use Operations within DTE Electric Sales and Marketing. In this role, I was responsible for managing third-party attachments to DTE Electric-owned assets. In November 2022, I started my current role as Director of Electric Marketing in the Electric Sales and Marketing organization of DTE Electric.

Q6. What are your current duties and responsibilities?

A6. My responsibilities as Director of Electric Marketing span three primary focus areas:

1. Transportation Electrification: support and accelerate EV adoption within DTE Electric's service territory and help the State of Michigan achieve its decarbonization goals;
2. New Product Development: assess and provide products and services, which support customer satisfaction and customer affordability, under the Value-Added Programs and Services ("VAPS") regulations;

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3. Customer Marketing: communicate with customers regarding DTE Electric rates and tariffs for electric service and address customer inquiries or complaints.

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to explain and support the programs, policies, and Company departments, along with any associated costs, for the five following areas:

1. Status of existing Charging Forward program components;
2. The Company's proposal for a Transportation Electrification Plan ("TEP");
3. Customer Collection – Merchant Fee expense;
4. Certain expenditures related to the 2023 full time-of-day ("TOD") roll out; and,
5. Electric Regulated Marketing operations and maintenance ("O&M") expense.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.9	Charging Forward Cost Projections
A-13	C5.7.1	Customer Service– Credit/Debit Card Merchant Fees
A-13	C5.9	Regulated Marketing Projected O&M Expenses
A-13	C5.9.2	TOD Regulatory Asset Deferral
A-29	T1	Charging Forward 4th Annual Status Report

Q9. Were these exhibits prepared by you or under your direction?

A9. Exhibit A-29, Schedule T1 was prepared under my direction pursuant to the Orders dated May 2, 2019 and May 8, 2020 in Case Nos. U-20162 and U-20561, respectively. Exhibit A-13, Schedule C5.9.2 is co-sponsored with Company

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Witnesses Hatsios and Sparks. The remaining exhibits were prepared under my direction in support of the instant case.

1. Status of Existing Charging Forward Program Components

Q10. What is the status of the pilots in the existing Charging Forward program?

A10. In May 2019, the Commission issued an Order in Case No. U-20162 approving the original Charging Forward and funding was exhausted by year-end 2023. Building on the momentum of the fleet element in the original Charging Forward program, the Company proposed Charging Forward eFleets ("eFleets") in Case No. U-20935 in December 2020 and received approval in March 2021. The third iteration of funding for the Charging Forward Expansion ("Expansion") was approved in November 2022 in Case No. U-20836. Most recently, in December 2023, the Michigan Public Service Commission ("MPSC") approved funding in Case No. U-21297 to continue Charging Forward programming through 2024.

Q11. What elements of Charging Forward programming are categorized as permanent programs or pilots?

A11. The Charging Forward programming elements are categorized as follows:

- Permanent program offerings[1]: Education & Outreach, Emerging Technology Fund, and Program Administration;
- Pilot offerings: Home Charger Rebates, Home Charger Install, EV Rebates, Business Charger Rebates, Business Charger Installation, eFleet Charger Rebate, eFleet Battery Support, School Bus Chargers and Charging Hubs.

[1] As approved annually through 2028 with the December 1, 2023 Order in Case No. U-21297

Q12. What is the Company's total expected investment for the existing Charging Forward program?

A12. The total actual and estimated future investments for the existing Charging Forward program, through the end of 2024, are summarized in Table 1 below.

Table 1 Actual & Estimated Program Investment (in $ thousands) by Element[2]

Program Element	2019	2020	2021	2022	2023	2024	Total
Program Administration	273	448	648	965	1,610	1,813	**5,757**
Education & Outreach	382	202	365	1,216	1,036	1,800	**5,001**
Business and eFleet Charger Rebates	162	511	1,858	2,599	2,927	11,996	**20,054**
Home Charger Installation					520		**520**
Business Charger Installation						3,315	**3,315**
Charging Hubs					96	1,800	**1,896**
eFleet Battery Support						5,000	**5,000**
School Bus Chargers						2,000	**2,000**
Residential Customer Rebates[3]	48	121	290	655	1,828	2,000	**4,941**
Additional Elements	227	119	112	564			**1,022**
Emerging Tech Fund					825	1,000	**1,825**
Total	**1,092**	**1,401**	**3,273**	**6,000**	**8,842**	**30,724**	**51,332**

The capital, O&M, and regulatory asset treatment of the above investment is shown in Table 2 below.

[2] Differences in totals due to rounding
[3] Residential Customer Rebates include Home Charger Rebates and EV Rebates

Table 2 Actual & Estimated Program Investment (in thousands) by Type[4]

Spend Type	2019	2020	2021	2022	2023	2024	Total
Capital	64		196	15	994	12,509	**13,778**
O&M					922	2,293	**3,214**
Regulatory Asset	1,028	1,401	3,078	5,985	6,927	15,922	**34,341**
Total	**1,092**	**1,401**	**3,274**	**6,000**	**8,842**	**30,724**	**51,332**

Exhibit A-12, Schedule B5.9 shows the total estimated calendar year investment (lines 1 through 24) for the following periods:

- January, 1 2022 to December 31, 2022 ("historical period") in column (b);
- January 1, 2023 to December 31, 2024 ("bridge period") in column (e); and
- Total actual and estimated pilot and permanent program costs for the historical and bridge periods are $6,000 thousand and $39,566 thousand, respectively, as shown in line 24.

Q13. What are the costs included in Program Administration?

A13. The December 1, 2023 Order in Case No. U-21297 approved $1.8M in annual O&M costs for Expansion Program Administration. The December 1, 2023 Order in Case No. U-21297 also continued regulatory asset treatment for approximately an average of $0.8 million in annual costs through the projected test year for eFleet Advisory Services, which was originally approved in Case No. U-20935.[5] The combined Program Administration investment enabled common elements for all permanent programs and pilots approved in the Charging Forward program, to be managed by a single budget and administrative team. The Company is in the process of ramping up a 14-person team to accomplish the objectives addressed in Case No. U-21297. The administrative team, currently at ten Full Time Employees

[4] Differences in totals due to rounding
[5] This approved plan for eFleet Advisory services spans the calendar years 2021 through 2025.

(FTEs), allocates 40% of its resources to eFleets (regulatory asset), 15% (capital) to reflect the work on capital projects, and 45% (O&M) on all other initiatives. By 2025, all Program Administrative spend will move to O&M. These expenditures are shown in lines 2, 12 and 15 of Exhibit A-12, Schedule B5.9 with actual investments of $1.0 million and $3.4 million for the historical and bridge periods in columns (b) and (e), respectively.

Q14. What are the costs for Education and Outreach (E&O)?

A14. There are no modifications to the Company's combined E&O budget for the Charging Forward program, as proposed and approved with the December 1, 2023 Order in Case No. U-21297, at a total of $1.5 million annually in O&M and $0.3 million in regulatory assets for eFleets. Lines 11 and 16 of Exhibit A-12, Schedule B5.9, shows the actual investment of $1.2 million for the historical period in column (b) and $2.8 million for the bridge period in column (e).

Q15. What are the costs for Business and eFleet Charger Rebates?

A15. The Company was approved a total of $24.4 million, with the December 1, 2023 Order in Case No. U-21297, for Business and eFleet Charger Rebates. This total includes $5.8 million to exhaust funding of the original Charging Forward pilot through 2023, $6.9 million for eFleets Business Charger Rebates through 2024, and $11.7 million for Expansion's Business Charger Rebates through 2024. The Company incurred decreased levels of approved and installed DCFC sites after implementing additional requirements[6] as ordered by the Commission that aligned

[6] DTEE site requirements and preferred site conditions for DCFC sites are available at https://www.dteenergy.com/content/dam/dteenergy/deg/website/business/service-and-price/pev/plug-in-electric-vehicles-pev/DCFCSiteRequirements.pdf

with the National Electric Vehicle Infrastructure (NEVI) projects. Furthermore, the Company's capital costs for public commercial DC fast chargers (DCFCs) turned out to be lower than initially projected. The conservative approach taken during the pilot phase contributed to this outcome and we intend to deploy these funds in 2024 to support projects that have well-justified use cases to ensure prudent investment. The eFleet project installations, tied to recipients of the Environmental Protection Agency's Clean School Bus Rebate Program, were also more conservative in terms of spend and timing. As a result of these insights, the Company reduced the total budget for this component by approximately $10 million. Added together, lines 3 and 18 of Exhibit A-12, Schedule B5.9, show the actual and projected investment of $2.6 million for the historical period and $14.9 million for the bridge period in column (b) and (e) respectively. We intend to deploy these funds in 2024 to support projects that are well-justified use cases to ensure prudent investment.

Q16. What are the costs for Home Charger Installation?

A16. The Company was approved $2.3 million, with the November 2022 Order in Case No. U-20836, for Home Charger Installation. The pilot commenced in early 2023 and by the end of 2023, had provided turnkey charger installation solutions for over 600 residential customers and approved over 40 installations scheduled to be completed in 2024, reducing financial and physical installation barriers to home charger ownership and EVs.

With the initial set up of the pilot for financing home EV charger installations, there was an overestimation of the capital expenditures required for the program. While

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the Company incurred upfront costs of $2.4 million to purchase and install the chargers and develop the necessary IT systems to set up and support the program, the appropriate accounting treatment is to record $1.9 million of these expenses as Receivables from customers. Instead of recovering the Receivables through base rates, the Company recovers those costs through a fee added to participating customers' bills. Thus the $1.9 million Receivable is not proposed to be included as part of the Company's base rate request in the instant case and is not included in Exhibit A-12, Schedule B5.9, Line 4, column (e). The remaining $0.5M of capital expenditure covers IT and program setup costs.

Additionally, around mid-year 2023, the Company received intervenor feedback on transitioning the pilot to value-added programs and services ("VAPS"), which also resulted in scaling back the investment as a regulated offering. With the recent December 1, 2023, Order for Case No. U-21297, the Home Charger Installation pilot has been terminated and the Company anticipates transitioning it to VAPS in 2024. Line 4 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b) and bridge period costs of $0.5 million in column (e).

Q17. What are the costs for Business Charger Installation?

A17. The Company was approved $3.5[7] million with the December 1, 2023 Order in Case No. U-21297 for Business Charger Installation. Lines 5 and 19 of Exhibit A-12, Schedule B5.9 show zero actual costs in column (b) and $3.3 million for bridge period costs in column (e).

[7] Total of $1.2 million for bridge period ($0.5 million capital and $0.7 million regulatory asset) and a total $2.3 million for test period ($1.0 million capital and approximately $1.3 million regulatory asset)

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Q18. What is the status of the Business Charger Installation program?

A18. Originally, the Company was meant to own the chargers. Instead, the pilot was modified to have the site hosts take ownership, while DTE Electric provides full support for utility infrastructure, customer readiness, and charger expenses. The Company intends to deploy the bridge period funding in 2024.

Q19. What are the costs for Charging Hubs?

A19. The Company was approved $2.8 million, with the November 2022 Order in Case No. U-20836, and $2.7 million, with the December 2023 Order in Case No. U-21297, for Charging Hubs. Line 6 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b), $1.9 million for bridge period costs in column (e) and $3.5 million for the projected test period costs in column (f).

Q20. What is the status for the Charging Hubs pilot?

A20. DTE Electric was approved to begin construction on up to two Charging Hubs designed for medium- and heavy-duty fleet vehicles providing multiple fast chargers in a single location. The Company is collaborating with federal grant partners, such as the State of Michigan, and Detroit Diesel (Daimler Truck North America) to fulfill grant requirements for the Department of Transportation's Rebuilding American Infrastructure with Sustainability and Equity, or "RAISE" program that awarded $8.5M of funding for the buildout of the first Charging Hub in Redford. The Company is focused on executing key activities in the bridge and test period which include defining roles and establishing partnership agreements, finalizing the scope of work through cross-coordination with partners, launching an RFP for the start of site design and engineering in 2024, and start of construction in 2025. Furthermore, the Company is scouting additional prospective sites to start construction in 2025 while also looking for available federal and state grant opportunities to maximize awards to the Southeast Michigan region in which DTE Electric serves.

Q21. What are the costs for eFleet Battery Support?

A21. The Company was approved $2.0 million, with the November 2022 Order in Case No. U-20836, and $3.0 million, with the December 1, 2023 Order in Case No. U-21297, for eFleet Battery Support. Line 7 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b) and $5.0 million for bridge period costs in column (e). The Company intends to continue to seek partners, in 2024, in support of the program.

Q22. What are the costs for School Bus Chargers?

A22. The Company received approval for $2.0 million with the December 1, 2023 Order in Case No. U-21297. Line 22 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b) and $2.0 million for bridge period costs in column (e).Since approval in December 2023, the Company has been working to establish the program and intends to deploy the funding in 2024.

Q23. What are the costs for Residential Customer Rebates?

A23. Residential Customer Rebates include Home Charger Rebates and EV Rebates. The Company received approval for $2.0 million with the November 2022 Order in Case No. U-20836, proposed $1.0 million for Home Charger Rebates and $1.0 million for EV Rebates in Case No. U-21297 and was approved a total of $2.0

million for both Residential Customer Rebates pilots. Line 17 of Exhibit A-12, Schedule B5.9 shows the actual investment of $0.7 million in column (b) and bridge period costs of $3.8 million in column (e).

Q24. What are the costs included in Additional Elements?

A24. In the November 2022 Order for Case No. U-20836, the Company was approved to exhaust the remaining funding for the $0.6 million budget as part of the expanded scope of Charging Forward based on stakeholder feedback[8]. The funding for the three Additional Elements supported costs for an EV-Grid Impact Study, an EV-Ready Builder Rebate Pilot (as proposed in Case No. U-20561), and an EV-Only Off-Peak Incentive Pilot ("Bring Your Own Charger"). Line 20 of Exhibit A-12, Schedule B5.9 shows the actual costs of $0.6 million in column (b) and zero bridge period costs in column (e).

Q25. What are the costs for the Emerging Technology Fund?

A25. The Emerging Technology Fund was approved for $0.9 million in Case No. U-20836, and $1.0 million annually for five years (through year 2028) with Case No. U-21297. Line 21 of Exhibit A-12, Schedule B5.9 shows zero actual costs in column (b) and $1.8 million in bridge period costs in column (e).

2. <u>The Company's Proposal for a Transportation Electrification Plan (TEP)</u>

Q26. What is the purpose of this section?

A26. In Case No. U-20836, the MPSC requested DTE Electric "to prepare and submit, with its next rate case, a full scale, well-developed, permanent Charging Forward

[8] Detailed further in the 3rd Annual Status Report (Exhibit A-29, Schedule T1) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000038iECAAY

proposal that includes a BCA [benefit-cost analysis].” As a result, the Company has spent the last year and a half developing a comprehensive TEP with robust analyses and careful evaluation of the role of the utility along with in-depth benchmarking and stakeholder consultation. The purpose of this section is to discuss the full TEP portfolio – approach, programs, and benefit-cost analysis – and seek approval of the expense for administering the TEP in 2025.

Q27. How is this portion of your testimony structured?

A27. This portion of my testimony is organized into the following four sub-sections:

I. Background and Approach

II. TEP Portfolio Proposal

III. TEP Benefit Cost Analysis

IV. TEP Investment

I. Background and Approach

Q28. What is DTE Electric’s overall vision for its TEP?

A28. DTE Electric’s goal is to power and enable a cleaner energy future for its customers through transportation electrification. The Company aims to do this in a series of ways:

- create a plan that enhances the state’s charging network and provides customers beneficial electric pricing options along with education and advisory services to help accelerate customers’ journeys to Electric Vehicle (“EV”) adoption,
- amplify EV benefits for all customers and intentionally break down barriers for low- and moderate-income customers and disadvantaged communities,

- integrate EV load with the grid of the future by using advanced technologies to reduce peak demand and minimize costs to all customers, and
- deliver reliable, cleaner energy to power EVs and reduce state-wide carbon emissions.

Q29. What are the Company's guiding principles used to develop the TEP?

A29. DTE Electric adhered to the following guiding principles in the development of the TEP:

- Support and accelerate EV adoption by facilitating charger deployment while ensuring that the portfolio maintains affordability benefits for all DTE Electric customers,
- Consider unique reasons for utility participation such as closing charging gaps and improving economics of electrification in the near-term, and
- Promote equity by focusing on low-income ("LI") customers and disadvantaged communities ("DACs").

Q30. What was the Company's approach to developing the TEP?

A30. The Company spent the last 15 months developing a comprehensive TEP by:

1. Conducting in-depth benchmarking,
2. Evaluating likely service requirements, including the number of chargers, charging infrastructure needed, and investment required,
3. Creating a framework to guide utility investment based on the Company's guiding principles, and,
4. Seeking stakeholder feedback, which was incorporated at multiple points in this process.

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Each of these steps is discussed in more detail below.

Q31. What was the Company's benchmarking process?

A31. The Company analyzed six utility TEPs in-depth,[9] chosen because of their recent proposal or approval and the robustness of their included programs. The Company also reviewed an industry benchmarking report in detail,[10] and has consistently participated in national EV working groups.[11] This work helped guide DTE Electric's strategy and TEP development.

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[9] The six utilities included in benchmarking include Commonwealth Edison (ComEd), Consolidated Edison (ConEd), National Grid Massachusetts (National Grid), Southern California Edison (SCE), Xcel Colorado, and Xcel Minnesota. The TEPs benchmarked are:

- ComEd Beneficial Electrification Plan available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf, accessed December 5, 2023
- ConEd Electric Vehicle Infrastructure Make-Ready Program Implementation Plan available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b181AB1C0-0F11-44F6-B652-5705D91EC1B3%7d, accessed December 5, 2023
- National Grid Direct Pre-filed Testimony of the Electric Vehicle Program Panel Exhibit NG-EVPP-1 available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106, accessed December 5, 2023
- SCE Application of Southern California Edison Company (U338E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K230/346230115.PDF, accessed December 5, 2023
- SCE Decision on the Transportation Electrification Standard Review Projects, SCE's Medium- and Heavy-Duty Vehicle Charging Infrastructure Program available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF, accessed December 5, 2023
- Xcel Colorado Transportation Electrification Plan 2021-2023 available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-_2021-2023_TEP_Updated.pdf, accessed December 5, 2023
- Xcel Minnesota Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b90B25F82-0000-C32B-B70E-1C25A3E2A491%7d&documentTitle=20228-188061-07, accessed December 5, 2023

[10] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023

[11] Alliance for Transportation Electrification, Midcontinent Transportation Electrification Collaborative, Electric Power Research Institute

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Q32. What was the Company's high-level overview from the review of the TEPs?

A32. The table below shows a high-level summary of the six TEPs at the time DTE Electric benchmarked them.

Table 3 Overview of Six TEPs Benchmarked as of Q4 2022[12,13]

Company	State	Electric Customers (millions)	Program Years	Investment ($ millions)	# Charger Ports (L2 | DCFC)	2030 EV Forecasts
ComEd	IL	4.1	'23-'25	$270	7,730 | 196	700,000
ConEd	NY	3.8	'21-'25	$290	18,500 | 457	500,000
National Grid	MA	2.2	'22-'25	$278	31,400 | 393	500,000
SCE	CA	1.4	'21-'25	$793	24,500 | 205	2,600,000
Xcel CO	CO	5.2	'21-'23	$108	19,800 | 210	500,000
Xcel MN	MN	1.5	'23-'26	$384	0 | 1,470	797,000

There are several key themes that emerged from the benchmarking:

1. Most of the TEPs outline investment and programs for a three- to five-year timeframe, which is longer than a typical general rate case bridge and test period,
2. The TEPs can accommodate programmatic changes, as needed, in a dynamic environment,
3. The TEPs generally emphasized Level 2 charging over DCFC to improve overall customer affordability, due to the higher number of use cases for Level 2 charging, lower costs of installing Level 2 chargers compared to DCFCs, and minimized grid impact, and

[12] Data for investment, program years, electric customers, and 2030 EV forecasts sourced from company TEP filings. Exceptions: # Charge Ports for SCE does not include the 870 sites approved for the Charge Ready Transport medium-duty and heavy-duty vehicle program; 2030 EV forecasts for ComEd and ConEd were estimated based on state EV targets and customer size

[13] Since Q4 2022, Xcel CO has reached a settlement agreement on its TEP, Xcel MN has since withdrawn its TEP, and National Grid has since received approval for portions of its TEP

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4. The TEPs often include an emphasis on compliance with statewide regulations, equity, multi-unit dwelling and fleet segments, supporting functions, and managing incremental EV load, as well as a trend towards make-ready incentives as opposed to utility ownership, discussed in more detail below.

Q33. What has the Company found with respect to TEP regulation?

A33. From a compliance perspective, seven states have legislative or regulatory requirements for their investor-owned utilities to file periodic TEPs with their utility commissions that describe the utilities' transportation electrification efforts for the next three to five years. Utilities in Colorado, Illinois, New Mexico, Oregon, and Washington are required to make such filings by state legislation while utilities in Arizona and Virginia are required to do so by their utility commissions. States that require TEPs generally call for updates every three to five years, reflecting the need to modify programming based on experience as well as to revise plans to address new transportation electrification goals or emerging state policies.[14]

Most states do not have requirements for their utilities to submit periodic comprehensive TEPs, including many states with utilities that are actively investing in transportation electrification. California and New York, together, account for most of the $3 billion in approved utility TE investments over the last 10 years in the United States, yet neither state requires utilities to engage in a comprehensive TEP process (although it has been proposed in California). In states like these, utilities have filed TEPs to align with statewide environmental initiatives including

[14] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023

statutory EV targets.[15] The most impactful of these has been California's Zero-Emission Vehicle ("ZEV") program and the related regulations that have set increasingly stringent EV sales targets in California since 1990, with the most recent amendment to the regulations, called the Advanced Clean Cars II regulations, requiring all new passenger vehicles sold in California to be zero-emission by 2035. Fifteen other states have since adopted the program.[16] These states and California are collectively called ZEV states, and their share of national EV sales is higher than their share of the national population.[17] This makes TEPs more likely to be filed in these states compared to non-ZEV states.

Q34. What has the Company found with respect to TEP equity policies?

A34. An emphasis on equity, through supporting DACs and low- and moderate- income ("LMI") residential customers, is a key theme in most TEPs. The TEPs benchmarked incorporated an equity focus in 20 to 40 percent of total plan investments. The most common way in which these utilities are focusing on equity is through enhanced program offerings for commercial customers located in DACs (the definition varying by utility and state) and for residential customers that are either located in DACs or that meet an income threshold set by the utility. For example, National Grid proposed $1,700 in make-ready and charger rebates for customers that are in designated Environmental Justice Communities or that meet

[15] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023
[16] Colorado, Connecticut, Delaware, Maine, Maryland, Massachusetts, Minnesota, New York, New Jersey, Nevada, Oregon, Rhode Island, Washington, Vermont, and Virginia
[17] Evaluating Electric Vehicle Market Growth Across U.S. Cities available at https://theicct.org/wp-content/uploads/2021/12/ev-us-market-growth-cities-sept21_0.pdf, accessed December 5, 2023

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the low-income threshold and only up to $1,000 for single-family homes ("SFHs") that do not meet these criteria.[18]

Q35. What has the Company found with respect to MUD and fleet policies?

A35. MUDS and fleets receive unique attention in most TEPs. MUDs do, mainly because of the coordination issues between residents and those who own the property or have a say in how it is managed, such as landlords or Homeowners Associations. These coordination issues stem from the residents wanting EV charging but needing these other stakeholders to approve or pursue the installation for them. Unless landlords and Homeowners Associations are motivated to do this, MUD residents are left without the ability to freely install chargers like single-family homeowners can. There is also typically an equity focus. The TEPs benchmarked by the Company feature increased incentives for, or programs limited to, MUDs located in DACs, MUDs serving LMI residents, or having some other equity focus. For example, Xcel Colorado has a utility-owned make-ready infrastructure program for MUDs and offers a charger rebate for MUDs that meet income-qualified criteria or that are in high emissions communities.[19]

Fleets, particularly medium- and heavy-duty vehicles ("MHDVs"), transit buses, and school buses, are another segment that receive unique attention, especially among larger utilities. Southern California Edison (SCE) has dedicated $356 million

[18] National Grid Direct Pre-filed Testimony of the Electric Vehicle Program Panel Exhibit NG-EVPP-1 available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106, accessed December 5, 2023; Environmental Justice Communities defined by the State of Massachusetts
[19] Xcel Colorado Transportation Electrification Plan 2021-2023 available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-_2021-2023_TEP_Updated.pdf, accessed December 5, 2023

through its Charge Ready Transport TEP to support the electrification of MHDVs by providing low- or no-cost charging infrastructure.[20, 21] As observed with MUDs, some TEPs also have equity-focused programs or enhanced incentives within their fleet programming. For example, Commonwealth Edison's (ComEd's) TEP proposal included a $120,000 rebate for electric school bus purchases while the rebate for the buses serving DACs is 50% higher at $180,000.[22]

Q36. What has the Company found with respect to the nature of TEP incentives?

A36. Make-ready infrastructure programs are the most commonly offered type of incentive program in the TEPs. A greater share of TEP capital budgets is allocated to make-ready infrastructure programs versus own-and-operate programs.[23] In an analysis of all United States utility TE filings from 2012 through Q3 2022, conducted by the Midcontinent Transportation Electrification Collaborative in 2022, nearly $2 billion had been allocated for make-ready infrastructure programs, whereas in that same period, less than $1 billion had been allocated for utility own-and-operate programs.[24] DTE Electric's benchmarking found this trend to be consistent in the three TEPs with significant capital budgets (excluding Xcel Minnesota's withdrawn proposal), with 90% of their capital budgets being allocated to make-ready infrastructure programs.

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[20] SCE Decision on the Transportation Electrification Standard Review Projects, SCE's Medium- and Heavy-Duty Vehicle Charging Infrastructure Program available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF, accessed December 5, 2023

[21] Charge Ready Transport Advances Despite Pandemic-Related Challenges available at Charge Ready Transport Advances Despite Pandemic-Related Challenges | Energized by Edison, accessed December 15, 2023

[22] ComEd Beneficial Electrification Plan available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf, accessed December 5, 2023

[23] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023

[24] Midcontinent Transportation Electrification Collaborative 2022 meeting; analysis only includes those filings listed on Atlas Public Policy EV Hub

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Q37. What did the Company find with respect to the handling of supporting functions in the benchmarked TEPs?

A37. The benchmarked TEPs dedicate between 10% and 25% of their total TE spend on other portfolio costs that include marketing, education, outreach, and program support such as IT and program administration. Utilities recognize the need to increase education on the benefits of EVs and spread awareness about their programs. Proposals include expanding their websites and working with local car dealerships. An extension of these programs, seen more commonly in the fleet segment, includes advisory services such as call centers or dedicated staff to advise customers. Per the ACEEE report, more than half the utility TEPs offer detailed fleet advisory services, including fleet assessments, which give fleet operators information on what electrification would cost them in terms of infrastructure investments and ongoing vehicle charging.[25]

Q38. What else did the Company learn?

A38. All benchmarked utilities emphasize the importance of strategically managing the incremental load from EV charging to mitigate grid impacts. Most utilities have participant requirements or incentives that support managed charging or Time of Day rates. Both can influence customer charging behavior by encouraging or requiring charging during off-peak hours. All utilities offer TOD rates to their residential program participants and use their educational resources to encourage off-peak charging. Although all utilities recognize the importance of strategically managing the transition of additional load from EVs, especially as adoption increases, managed charging is still in a relatively nascent stage. Only two utility

[25] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023

TEPs, those of National Grid and Xcel Colorado, offer an additional incentive for participants to enroll in managed charging programs, similar to the DTE Electric Smart Charge program today.[26,27]

Q39. What is the forecasted market size for EV registrations in DTE Electric's service territory?

A39. In DTE Electric's service territory of Southeast Michigan, EV sales have grown at a compound annual growth rate (CAGR) of 90% from 2019 to 2022, with approximately 13,100 EVs sold in 2022, compared to about 1,900 EVs in 2019. Year to date, 77% of the newly sold EVs in Michigan are registered in DTE Electric's service territory and 74% of these are all-electric.[28] There are currently almost 46,000 EVs registered in Southeast Michigan, and, as shown in the Figure below, the Company forecasts this number increasing to an estimated 326,000, including MHDVs, by 2028, which is the timeframe of the Company's TEP.[29]

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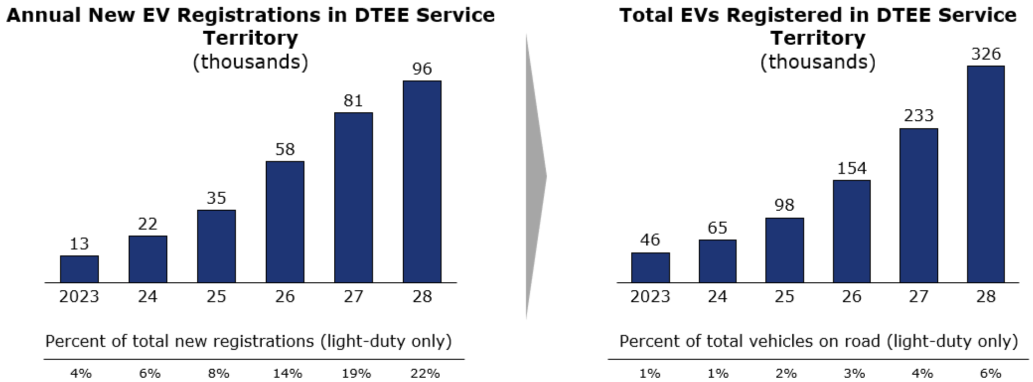
[26] Utility Transportation Electrification Planning—Emerging Practices to Support EV Deployment available at https://www.aceee.org/research-report/t2201, accessed December 5, 2023

[27] DTE Electric Smart Charge brochure available at https://www.dteenergy.com/content/dam/dteenergy/deg/website/residential/Service-Request/pev/plug-in-electric-vehicles-pev/SmartChargeBrochure.pdf, accessed December 11, 2023

[28] The balance are plug-in hybrid EVs; regenerative hybrids and hydrogen fuel cell vehicles are not considered EVs

[29] Data for 2023 from S&P Global as of September 30, 2023; registration volumes (both actual and forecasted) include medium-duty and heavy-duty vehicles

Figure 1 DTEE Forecast of Annual New EV Registrations and Cumulative Registered EVs [30]



Q40. How did the Company arrive at this EV registration forecast?

A40. This EV registration forecast, shown in the figure above, was derived from a combination of a short-term forecast developed using recent registration data from S&P Global and a long-term forecast derived from forecasts published by industry experts. For the short-term forecast in 2024 and 2025, EV registrations were determined using an exponential regression based on EV registrations in DTE Electric service territory from 2018 through 2023. For 2027 and 2028, DTE Electric EV registrations were derived from forecasts published in 2022 and 2023.[31] To get a Michigan EV forecast in the near term, a marginally lower forecast was factored in to account for the lower growth rate in the near term for a non-ZEV state. The fraction applied to the forecast to achieve this grows over time as, in the long term, the Michigan EV sales rate is expected to be closer to the national EV sales rates. 2026 is the average of the forecast in 2025 and 2027, as it is the transitionary year

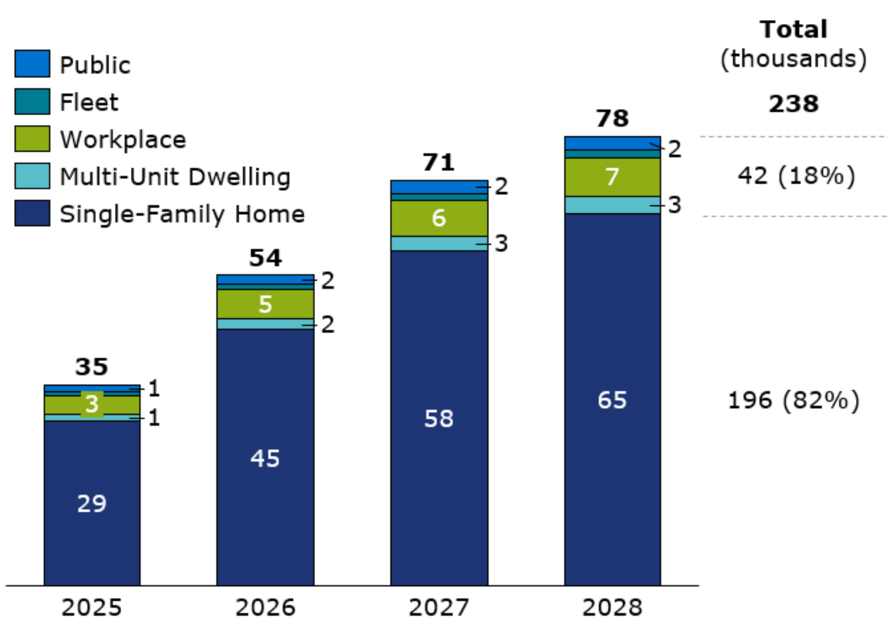
[30] Data for 2023 from S&P Global as of September 30, 2023; registration volumes (both actual and forecasted) include medium-duty and heavy-duty vehicles
[31] Including those from Bloomberg New Energy Finance, Goldman Sachs, Electric Power Research Institute, International Council on Clean Transportation, Boston Consulting Group, and the U.S. Energy Information Administration

between the short- and long-term forecasts. The Michigan EV forecast is then converted to a DTE Electric EV forecast by applying another factor representing the percentage of new EVs registered in the DTE Electric service territory compared to the total registered in the state.

Q41. What is the charging infrastructure required to support the forecasted EV adoption?

A41. The forecast shows an estimated increase to 326,000 EV registrations in 2028 from the approximately 46,000 EVs registered in DTE Electric's service territory in Southeast Michigan today. This increase in forecasted EV registration equates to approximately 238,000 chargers being needed in DTE Electric's service territory over the four-year TEP time horizon, increasing from approximately 35,000 chargers annually in 2025 to 78,000 annually in 2028, as shown in the figure below.

Figure 2 Forecast of Incremental Chargers Needed in DTEE Service Territory (thousands)



Line No.

More than 80% of the estimated chargers needed to support the forecasted EV adoption from 2025 through 2028 are projected to be at single-family homes. The majority of the incremental chargers needed are Level 2 chargers, driven by the residential segment that includes both single-family homes and MUDs.

Q42. How was this charging infrastructure requirement evaluated?

A42. First, the Company developed an overview of the needs of the five primary customer segments. The five primary customer segments are consistent with the TEPs benchmarked and are described in the table below.

Table 4 Overview of Primary Customer Segments and Needs

Segment	Customer Description	Market Needs
SFHs	Residential customers in detached homes which generally have a single electrical panel (includes buildings with three or fewer housing units)	• Longer duration charging is possible, so it can be served by Level 2 chargers (Level 1 charging was not considered for this analysis) • Cost of installation, which can be as much as $8,000, can be barrier for low-income customers
MUDs	Commercial customers with buildings that have four or more housing units. Parking may be in shared lots or designated parking spots	• Longer duration charging is possible, so it can be served by Level 2 chargers except in unique situations (e.g., no parking) • If landlords lack motivation to install chargers, it deters EV adoption for residents
Public	Commercial customers owning chargers for public use, either at a destination (e.g., stores and restaurants) or on-route near a major throughway	• In some areas, Level 2 chargers are sufficient, but majority of charging needs, in the future, will be fulfilled by DCFCs that have a shorter charging time • In 2023, there was a lack of public charging infrastructure in disadvantaged and rural communities

		identified within DTE Electric service territory
Fleet	Commercial customers owning chargers for business use. Fleets can be one or more light-duty vehicles and/or MHDVs	• Type of charger needed varies depending on type of EV, vehicle miles traveled, and parking duration(s) • Large fleet depots, particularly for MHDVs, can have high installation costs
Workplace	Commercial customers owning chargers for employee use with their personally owned vehicles	• Longer duration charging is possible, so it can be served exclusively by Level 2 chargers. Over time, workplaces may be served by DCFCs, as well

Once the customer segments were defined, DTE Electric's EV registration forecast was proportioned into each customer segment.

The formula shown in the figure below was used to calculate the incremental number of chargers by customer segment and charger type (Level 2 or DCFC) for a given year:

Figure 3 Formula for Incremental Number of Chargers, by Customer Segment and Charger Type

$$Chargers = \frac{\frac{Number\ of\ EVs}{EVs\ per\ Charger\ Port} \times Charger\ Mix}{Ports\ per\ Charger}$$

The incremental number of EVs forecasted each year was divided by the number of EVs served per charger port to arrive at the number of ports. EVs per charger port is assumed to be as low as one for single family homes and as high as approximately 200 for public on-route charging in 2028. The assumption is that the number of EVs per charger port increases over time, as adoption of EVs increases and chargers are utilized more efficiently.

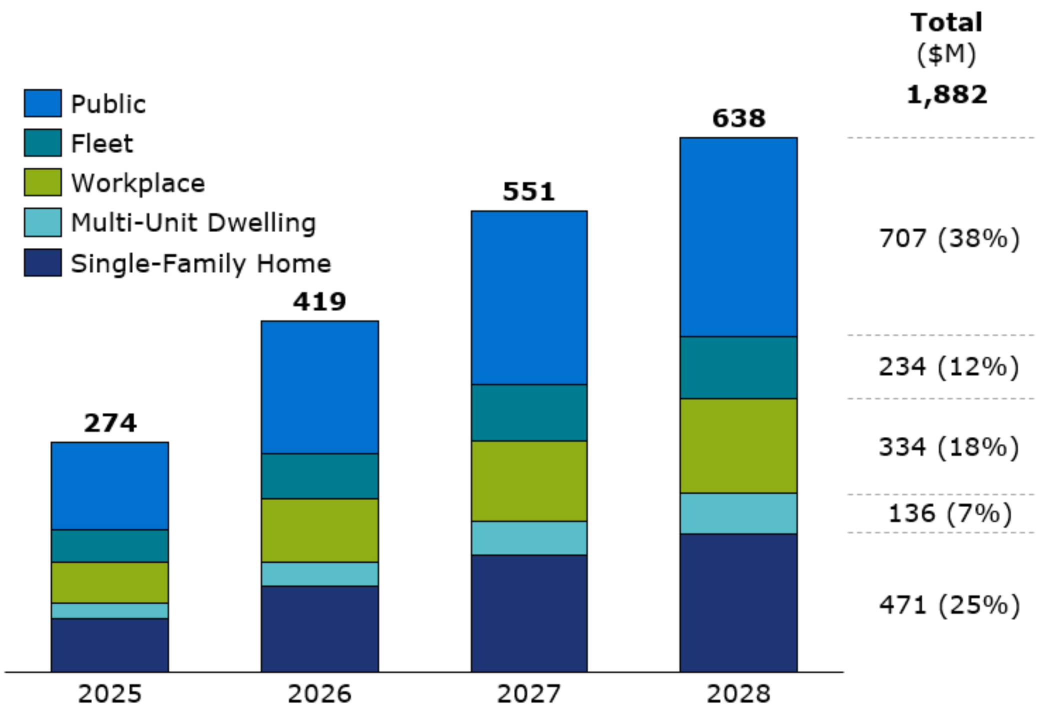
The number of ports calculated above was then segmented into charger type by multiplying the number by the charger mix, which is a percentage representing the assumed share of Level 2 or DCFC ports for that segment. The charger type for single-family homes and MUDs was assumed to be 100% Level 2 chargers since longer duration parking is expected. Public charging was assumed to be primarily DCFCs. For fleet charging, the charger mix varies by use case and vehicle type; the Company assumed 80% Level 2 charging for light-duty vehicles, 80% DCFCs for larger vehicles and 100% DCFCs for buses.

Finally, the number of ports for each charger type was divided by the number of ports per charger to arrive at the number of chargers by customer segment. The number of ports per charger ranges from one to 1.3, depending on the segment and the year. For example, one port per charger is assumed for single-family homes and school buses, while the need for public charging increases to 1.3 ports per charger in 2028.

Q43. What is the estimated investment required to support the number of chargers needed?

A43. The approximately 238,000 incremental chargers needed over the four-year TEP time horizon will require nearly $1.9 billion of infrastructure investment, funded by a mix of public, private, government, and utility sources, increasing from approximately $274 million in 2025 to $638 million in 2028, as shown in the figure below:

Figure 4 Annual Investment Required for Charging Infrastructure in DTE Electric Service Territory by Customer Segment ($ millions)



Even though the public charging segment represents just 3% of the chargers needed, as shown in the figure above, it is the largest driver of investment required in the near term at nearly 40% due to the high costs of DCFCs and the associated installation. Conversely, although the single-family home charging segment represents over 80% of the total projected chargers, they only require about 25% of the total investment since they are much less expensive.

Q44. What assumptions were made in order to calculate the estimated investment needed?

A44. DTE Electric data were used to define cost assumptions by charger segment and type, as shown in the table below:

Table 5 Average Approximate Installation Costs by Charger Type and Segment, 2025-2028[32]

Type	Segment	Utility Make-Ready	Customer Make-Ready	EV Charger	Total Cost
Level 2	SFH	$230	$1,580	$590	$2,400
	MUD	$1,360	$13,600	$590	$15,550
	Workplace	$330	$13,310	$1,460	$15,100
	Fleet	$1,040	$12,960	$1,440	$15,440
	Other Public	$1,250	$12,520	$1,450	$15,220
DCFC	School bus	$16,510	$61,900	$32,750	$111,160
	Transit bus	$16,510	$61,890	$79,010	$157,410
	Workplace	$5,480	$65,770	$78,210	$149,460
	Fleet	$16,500	$61,870	$78,680	$157,050
	On-route	$20,630	$61,890	$78,790	$161,310
	Destination	$17,710	$53,130	$76,320	$147,160

The Company also considered the following factors in developing its cost assumptions:

- Inflation,
- Charger costs decreasing by 3% each year due to expected technological advancements, and

[32] Rounded to the nearest 10. Definitions and specific examples for utility make-ready, customer make-ready, and EV charger equipment are provided in Table 7 below. Utility make-ready includes customer-owed CIAC (typically 15% of total utility make-ready on average) and non-CIAC utility make-ready for which DTE Electric is responsible

- For every increase in project size by two chargers, charger costs were reduced by 2% and installation costs were reduced by 5% for Level 2 chargers and 10% for DCFCs, on a per-charger basis. No further per-charger cost savings were assumed for project sizes over ten chargers.

The impact of these factors on the cost assumptions is that charger and installation costs decline as the number of chargers per location increases, and for a fixed number of chargers per location, charger costs decline and installation costs increase over time.

DTE Electric also reviewed internal project data that indicated that 20% of fleet installations and 75% of workplace installations did not require any service upgrades, so the utility make-ready ("UMR") costs for these segments were reduced accordingly. For single-family homes, the internal project data revealed that the average customer make-ready ("CMR") cost for "newer" buildings (built in 1980 or after) is about half the average CMR cost for "older" buildings (built before 1980). Similarly, it is estimated that newer single-family homes would experience about a five-year delay on the kinds of UMR costs that older SFHs typically incur today.

The investment required does not include transmission or power supply costs.

Q45. What was the Company's approach to engaging stakeholders in the TEP design?

A45. DTE Electric engages stakeholders in its current Charging Forward programs by, among other things, hosting annual stakeholder discussions and submitting quarterly and annual status reports in the Case No. U-20162 docket. Listening to stakeholders during the TEP development helped DTE Electric produce a well-balanced and well-aligned plan to serve customers. The Company implemented a stakeholder engagement process aimed at providing transparency and obtaining feedback on the overall approach and development phases of the planning to ensure that its TEP balances the diverse interests of its stakeholders. This was achieved through a series of webinars and surveys and included:

- Focused discussions with the MPSC,
- A kick-off webinar with stakeholders to explain the TEP approach, discuss the guiding principles, and request their engagement,
- Three separate webinars for the three key stakeholder groups (defined below) to share our need assessment, customer segmentation, and charger installation cost categories and to seek insights into stakeholder positions on key things like which needs that DTE Electric should support, and whether the Company should consider waiving Contribution in Aid of Construction ("CIAC") for residential or business customers,
- Three surveys following each stakeholder webinar to allow the stakeholders to provide additional feedback, and
- Individual follow-up meetings with organizations, if requested.

DTE Electric invited 110 organizations to engage in this process and about half of the organizations invited participated, of which half belonged to the EV Industry stakeholder group.

Q46. What were the three key stakeholder groups?

A46. DTE Electric included more than 100 organizations that could be impacted by the TEP and organized these into three key stakeholder groups: EV industry, customer-facing, and policy & advocacy groups. The types of organizations in those key stakeholder groupings are shown in the table below:

Table 6 Types of Organizations in the Three Key Stakeholder Groups

EV Industry	Customer-Facing	Policy & Advocacy
• Auto manufacturers • Charger manufacturers • Network providers • Charger installation companies	• Municipalities • Regional planning organizations • Transit agencies • Businesses • Gas and convenience store owners • Rental car companies • Transportation Network Companies	• MPSC • Regional advocacy groups • National advocacy groups

Q47. What insights were garnered from stakeholders?

A47. Stakeholders provided feedback through the stakeholder engagement process, most of which was fairly aligned. There were some areas where stakeholders had divergent opinions. The feedback that most stakeholders were aligned on included:

- There is a need to provide charger rebates to facilitate EV adoption in the near term,
- Utility TEPs should have a strong focus on multi-unit dwellings, low-income customers, and disadvantaged communities,
- The resulting portfolio should provide net affordability benefits to all DTE Electric customers using a robust BCA, and

- DTE Electric should also focus on grid modernization to help improve reliability and on streamlining interconnection timelines to improve the customer experience.

The process also identified the following differing positions:

- Utilities should own chargers for specific use cases, such as curbside Level 2 charging and rural fast charging *versus* utility ownership should be minimal and encouraged as a last resort,
- There are clear failures in the EV charger market today *versus* it is premature to assume failures in the nascent EV market in Michigan,
- Utilities should waive CIAC from customers *versus* cost causation principles of rate design (and appropriate credits based on expected load and revenue) should remain in place for EV requests, similar to new service requests and upgrades, and
- Charging infrastructure needs and corresponding investment identified in the need assessment for DTE Electric's TEP should be based on the aspirational EV goal of two million EVs by 2030 in the MI Healthy Climate Plan *versus* basing them on DTE Electric's EV forecast.[33]

Q48. How was the TEP informed by stakeholder feedback?

A48. In accordance with the Company's guiding principles, DTE Electric had already envisioned supporting and accelerating EV adoption by facilitating charger deployment while ensuring affordability benefits for all DTE Electric customers and promoting equity by focusing on low-income customers and disadvantaged

[33] MI Healthy Climate Plan available at https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed December 18, 2023

communities, which are things that TEP stakeholders valued as well. After receiving insights from stakeholders, DTE Electric also decided:

- not to waive CIAC beyond revenue credits from existing line extension policy,
- to use its own EV forecasting methodology to determine charging infrastructure needs, and
- not to include utility-owned pole-mounted chargers with this initial TEP.

The Company believes that there is merit in the utility owning and operating pole-mounted chargers due to the lower costs along with the opportunity to seek federal funding at scale, and the ability to provide more affordable overnight charging solutions for DACs and MUDs. However, in order to achieve consensus where possible, the Company has opted not to include any utility-owned charging with its initial TEP.

Q49. What framework did DTE Electric use to develop the TEP?

A49. DTE Electric evaluated the participation models for each of the customer segments, leveraging the guiding principles and stakeholder feedback.

First, DTE Electric defined the three primary cost categories for charger installation and refined the five primary customer segments.

The three primary cost categories for charger installation help provide considerations for utility support for EV charging. Definitions and specific examples for these three cost categories, which include utility make-ready, customer make-ready, and EV chargers are provided in the table below:

Line No.

Table 7 Charger Installation Cost Category Definitions and Examples

	Utility Make-Ready	Customer Make-Ready	EV Charger
Description	• Upgrades on the utility side of the meter, from the line transformer to the meter	• Upgrades on the customer side of the meter, from after the meter to the EV charger stub out	• Hardware required to charge the EV
Examples	• Grid edge infrastructure (e.g., pole top transformer) needs to be upgraded to support residential EV load • Another service line needs to be added to support EV chargers in a parking lot	• A residential customer upgrades the panel to support an EV Charger • A commercial customer installs conduit and cable from the panel to the charger stub out	• Level 2 chargers • DCFCs

The five primary customer segments were further divided into sub-segments to allow DTE Electric to examine specific needs and dynamics at a more granular level to appropriately determine the degree to which the Company should participate. These sub-segments are defined in the table below:

Table 8 Overview of Customer Sub-Segments

Segment	**Customer Sub-Segments**	**Description of Location or Use Case**
Single-Family Homes	Low-Income	Level 2 chargers for SFH residents within 200% of federal poverty limit
	Non-Low Income	All other Level 2 chargers at SFHs
Multi-Unit Dwellings	Low-Income	Level 2 chargers at affordable MUD housing (e.g., public housing, government-subsidized private housing, etc.)
	Non-Low Income	All other Level 2 chargers for MUDs
Public	DAC/rural on-route DCFC	DCFCs within one mile of a major throughway and in DACs and/or rural areas
	All other on-route DCFC	All other DCFCs within one mile of a major throughway
	Destination DCFCs	All DCFCs further than one mile from a major throughway
	Destination Level 2	All Level 2 public charging, including pole-mounted charging
Fleet	Transit agencies	DCFCs serving transit buses
	Schools	DCFCs serving school buses
	Level 2	Level 2 charging for fleet EVs, typically light-duty vehicles
	All other DCFCs	All other DCFCs for fleet EVs
Workplace	-	Chargers for employee use with personally owned vehicles

The ways in which DTE Electric ultimately decided to support the above customer sub-segments, including justification for its proposal are included in the following TEP Portfolio Proposal section.

II. <u>TEP Portfolio Proposal</u>

Q50. What are the Company's proposed TEP programs?

A50. DTE Electric's proposed TEP programs achieve its guiding principles by facilitating charger deployment while maintaining overall affordability benefits for all DTE Electric customers, improving economics of electrification in the near-term, and promoting equity with a focus on low-income customers and disadvantaged communities. The portfolio is summarized in the table below:

Table 9 Proposed TEP Rebate Programs, 2025-2028

Customer Segment	Customer Sub-Segments	Rebate[34]	Segment Availability	Total Investment ($ millions)
SFHs	LI Level 2	$2,200	100%	24.0
MUDs	LI Level 2	$14,400	90%	7.0
	Non-LI Level 2	$5,000	45%	20.7
Public	DAC/rural on-route DCFC	$70,000	35%	21.6
	All other on-route DCFC	$50,000	35%	15.4
Fleet	Transit bus DCFC	$70,000	100%	2.3
	School bus DCFC	$70,000	30%	7.0
	Other DCFC	$70,000	30%	20.0
	Other Level 2	$2,500	90%	6.8
Total	-	-	-	124.8

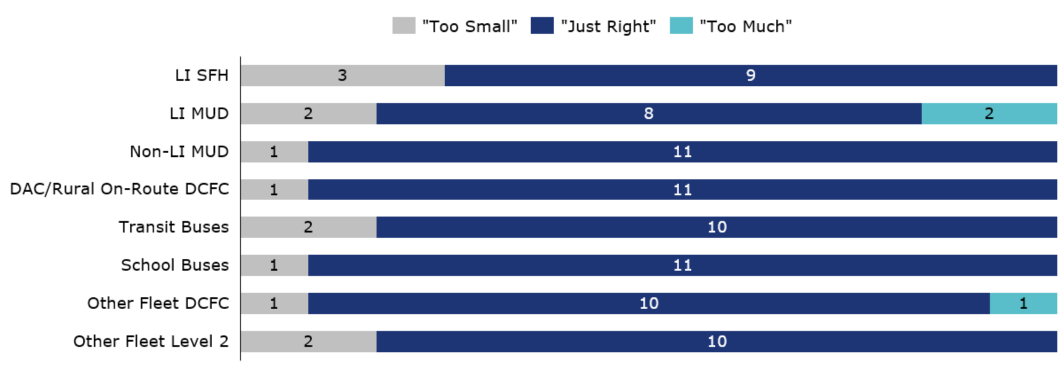
The on-route charging segment makes up the biggest category of investment at 30%, followed closely by fleet at 29%, MUDs at 22% and single-family homes at 19%. A benefit cost analysis is provided in the next section.

[34] LI SFH and LI MUD are average estimates based on total installation costs and would not exceed actual costs

Q51. How was the final portfolio informed by stakeholder feedback?

A51. The Company provided a preview of its proposed TEP programs to the stakeholders in October 2023 and sent a survey to participants following the discussion. 83% of the survey participants stated that they were either "satisfied" or "very satisfied" with the proposed TEP programs; the balance stated they were "neutral". The figure below shows the survey responses on the proposed rebate amounts by customer sub-segment:

Figure 5 Survey Responses to Proposed Rebate Amounts by Sub-Segment[35,36]



The greatest impact stakeholder feedback had on the final proposed TEP was the inclusion of the non-DAC/Rural on-route DCFC customer segment in the TEP. This customer segment was not included in the TEP preview shown to stakeholders, and as such is not included in the survey questions shown in the previous figure. In

[35] The 12 survey respondents included representatives from BorgWarner, BP Pulse, ChargerHelp, EV Connect, Flo EV Charging, General Motors, Michigan Auto Dealers Association, Michigan Energy Innovation Business Council (MEIBC), Michigan Public Service Commission, Southeast Michigan Council of Governments (SEMCOG), Tesla, and University of Michigan.

[36] Note that non-DAC/Rural on-route DCFC is missing from this survey, because this customer segment was not included in the TEP preview this survey was designed to complement, but in response to stakeholder feedback it was added to the final proposed TEP.

response to stakeholder feedback at this and other webinars (for example, stakeholders ranked this customer segment the third-most important for utility action), the Company decided to add the non-DAC/Rural on-route DCFC customer sub-segment to the final portfolio of proposed TEP programs.

Q52. What is the justification behind the Company's support of the Single-Family Home segment?

A52. The Company is proposing support for Home Charger Rebates for low-income residential customers in single family homes over the TEP timeframe at 100% of the forecasted charger deployments for this subsegment in the DTE Electric service territory, for a total investment of approximately $24 million. The proposed rebate would cover the cost of the Level 2 charger and the full cost of the customer's installation and is calculated at an average of $2,200 per rebate.

The Company has focused its support on the low-income single-family home subsegment for these reasons:

- While over 80% of the chargers needed between 2025 and 2028 are expected to be in the single-family home segment, per Figure 2 above, the Company and stakeholders believe that EV adoption in the non-low-income sub-segment is unlikely to be solely determined by the cost to install a home charger. However, this can be a significant barrier for low-income residential customers,
- Customers need to install a charger at home to unlock the fuel pricing of approximately $1 eGallon equivalent and experience the benefits and features of a dedicated EV charger,

- Customers can face high installation costs due to outdated electrical wiring and/or breaker panels. While the average total cost of installation is $2,400,[37] the range can vary from as low as $750 to as high as $7,850, based on a review of more than 500 installations completed through the Company's Home Charger Installation pilot program,
- The Company received strong stakeholder support for this approach with one key stakeholder stating, in a feedback webinar, that "[the low-income] community needs resources to move to EV adoption. This segment cannot be left behind."

Q53. What participation criteria will the Company require for the income-qualified Home Charger Rebates?

A53. Initially, the Company envisioned a low- and moderate-income customer eligibility threshold of 400% of the federal poverty limit. Some key stakeholders gave us feedback that this was too high. Consequently, DTE Electric lowered the income eligibility threshold to 200% of the federal poverty limit, which aligns with the threshold for other DTE low-income programs[38] and would be approximately $60,000 for a four-person household.

Other qualification requirements are:

- Proof of EV purchase or lease,
- Installation of an ENERGY-STAR certified or vehicle manufacturer charger less than or equal to 12 kilowatts, and

[37] Total cost of installation includes DTE Electric costs of about $200 for non-CIAC utility make-ready
[38] The Energy Efficiency Assistance program and Shutoff Protection Plan are two such DTE programs

- Enrollment in a Time of Day ("TOD") rate, such as Whole-Home TOD (D1.2), Dynamic Peak Pricing (D1.8), EV-only TOD (D1.9), or the recently approved Overnight Savers (D1.13).

Q54. Are there additional considerations for the income-qualified Home Charger Rebates proposal?

A54. Yes. It will be critical to monitor and adjust the income eligibility threshold based on market dynamics of EV adoption. For example, if the upfront premium for EVs continues to remain out of reach for low-income customers, DTE Electric may need to adjust the income threshold of the Home Charger Rebate program upwards to meaningfully support this segment and encourage EV adoption in Southeast Michigan.

Q55. What is the justification behind the Company's support of the Multi-Unit Dwelling segment?

A55. The Company is proposing to support the multi-unit dwelling ("MUD") segment for both low-income MUD housing and for all other MUDs with two separate programs.

The Company is proposing support for rebates for qualified low-income MUDs at about 90% of the forecasted MUD charger deployments in this subsegment over the TEP timeframe, for a total investment of approximately $7 million. The proposed income-qualified Business Charger Rebate would cover the cost of the Level 2 charger and the full cost of the installation that the customer is responsible for paying, including the CIAC portion of the utility make-ready and the customer make-ready. The average rebate is calculated at $14,400 per charger.

The Company is also proposing support for all other MUDs at about 45% of the forecasted MUD charger deployments in this subsegment over the TEP timeframe, for a total investment of approximately $20.7 million, to cover the cost of the charger and a portion of the installation. The proposed revised Business Charger Rebate would be $5,000 and would cover the cost of the Level 2 charger.

The Company proposes supporting this segment in this manner for the following reasons:

- As discussed in the single-family home segment above, access to overnight charging is critical to unlock fuel savings and this can be a purchase barrier for EVs,
- The average total cost of installation (less utility-owned non-CIAC utility make-ready) is approximately $14,400 over the TEP timeframe, as shown in Table 9, driven primarily by customer make-ready, which often requires trenching and extending electrical wiring to parking areas,
- The cost of installation can make it a challenge for landlords, especially in the low-income or affordable housing subsegment, to install EV chargers,
- While landlords in segments other than the low-income subsegment may have some incentive to install chargers as an amenity to attract tenants and retain occupancy, landlords in the low-income subsegment may not have the same motivation or resources to install EV chargers,
- As discussed above, benchmarking shows that MUDs are receiving unique attention in other utility TEPs due to some of the same reasons outlined above, and

- Stakeholders surveyed by DTE Electric ranked the low-income MUD housing segment as the fourth most important subsegment for utility action.

Q56. What participation criteria will the Company require for the rebates in the MUD segment?

A56. To qualify for the income-qualified Business Charger Rebate, the MUD must meet at least one of the following criteria:

- MUD is owned and managed by a public entity such as the Housing Commission,
- MUD receives government subsidization that requires at least 40% of the units to be for residents whose household incomes do not exceed 60% of the area median income (such as the LI Housing Tax Credit),
- MUD has at least 40% of their residents participating in the Housing Voucher Program, or
- Other criteria deemed equivalent to those above.

Qualification requirements proposed for both income-qualified and non-income qualified Business Charger Rebates include:

- Installation of a qualified, networked charger (similar to the Business Charger Rebates program today),
- Authorizing network provider to share charger data with DTE Electric,[39]
- Commitment to 97% charger uptime, and

[39] Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

Line No.

- Demonstrated tenant interest in installing EV chargers; this helps protect utility investment through greater likelihood of utilization of charging-related assets and investment.

Q57. Are there additional considerations for the Business Charger Rebates for multi-unit dwellings?

A57. Yes. There are two additional considerations for the Business Charger Rebates in the multi-unit dwelling segment:

1. The Company believes that Level 2 charging is appropriate for the longer parking duration at MUDs. This enables fuel savings for tenants while minimizing impacts to the DTE Electric grid. However, the Company is proposing that an exception could be made to allow rebates for DCFCs at MUDs in special cases, for example, if there is extremely limited parking space for residents.
2. One quarter (25%) of the stakeholder survey respondents indicated that DTE Electric's proposed support of the low-income MUD market was too much and one quarter (25%) of the survey respondents indicated that DTE Electric's support of the non-low-income MUD market was not enough. These results warrant the flexibility for DTE Electric to adjust the low-income MUD housing qualification requirements and the rebate amounts in this segment based on market demand to help appropriately enable MUD resident EV adoption during the TEP timeframe.

Q58. Can you explain the reasons for the Company's support of the Public Charging segment?

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A58. Stakeholders ranked all the public charging subsegments, including on-route and destination charging, as the most important for utility action because the availability of public charging is critical to reducing range anxiety, which is a key barrier to EV adoption. Reliable, on-route fast charging, defined as fast charging within one mile of a major throughway exit, can increase customer's confidence in the refueling infrastructure and so, the Company is proposing to provide support for on-route public fast charging by offering a rebate of $70,000 per on-route DCFC in disadvantaged communities and rural areas and $50,000 per on-route DCFC in other areas. To manage affordability impacts to its customers, DTE Electric proposes to support 35% of the forecasted on-route public charger deployment for an investment of $21.6 million in the DAC and rural on-route subsegment and $15.4 million in other on-route areas.

As noted above, public charging represents the highest category of investment required over the TEP timeframe because of the expensive hardware and the high cost of installation of DCFCs driven by high-voltage wiring. Site hosts seek higher utilization rates to recoup their investments which tends to concentrate private sector investment in higher-income areas that have high EV adoption rates. This is reflected in DTE Electric's increased support for the DAC and rural on-route subsegment as compared to the other on-route areas.

The Company expanded its support to on-route DCFCs not in DAC or rural areas based on stakeholder feedback in the development phase. Stakeholders consider utility support in this area critical in the near-term to decrease range anxiety and to complement available federal funding opportunities, such as the NEVI program.

DTE Electric does not, however, propose rebates for the destination charging segments as the economics of Level 2 charger deployment are not as challenging, and businesses have other motivation for installation such as increased foot traffic. For site hosts installing a destination DCFC, DTE Electric will continue to offer a commercially available rate without demand charges for sites less than one megawatt.[40]

Q59. What participation criteria will the Company require for its on-route Business Charger Rebates program?

A59. Participating customers will need to install a qualified, networked charger (similar to the Business Charger Rebate program today), authorize the network provider to share charger data with DTE Electric, and commit to 97% charger uptime.[41]

To qualify for the DAC on-route rebate, a community will need to be identified as disadvantaged by the Michigan State Plan for EV Infrastructure Deployment.[42] To qualify for the rural on-route rebate, a community will need to be identified as rural as viewed on the U.S. Department of Transportation Rural Eligibility Map.[43]

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[40] General Service Rate D3 as described in DTE Electric Company Rate Book for Electric Service available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cur.pdf?rev=e0168ab41b8245bba5f3ca7631c29614&hash=D16249E421EC5AB0F5C3A2304B0FB0F7, accessed December 18, 2023. Sites over one megawatt also qualify through June 2026

[41] Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

[42] Michigan State Plan for EV Infrastructure Deployment available at https://www.michigan.gov/mdot/travel/mobility/initiatives/nevi, accessed December 18, 2023

[43] Rural defined as, "located outside of a U.S. Census-designated urban area with a population of 50,000 or more." Rural Eligibility available at https://www.transportation.gov/rural/eligibility, accessed December 11, 2023

Q60. How does the Company propose continuing its support of the Fleet Charging segment?

A60. Transit and school bus electrification have received unique attention in governmental policy and funding programs due to the expected community benefits. Due to the high upfront premium of electric buses, additional support is often needed to improve economics even with the available funding. Although school bus chargers are lower cost, on average, than transit bus chargers, schools require more incentives to convert since the buses drive fewer miles than transit buses and so do not achieve the same level of fuel savings to offset the upfront premium. DTE Electric stakeholders ranked this subsegment high in terms of importance for utility action, following public charging and low-income MUDs (see Figure 5).

Therefore, the Company is proposing to continue its eFleet Charger Rebate program for both school and transit buses with a rebate of $70,000 per DCFC, assuming 60 kW and 150 kW DCFCs for those subsegments respectively. DTE Electric proposes supporting 100% of the transit bus charger subsegment over the TEP timeframe for a total investment of approximately $2.3 million. The Company proposes a total investment of approximately $7 million to support 30% of the forecasted school bus chargers needed while interest and affordability evolves.

DTE Electric also proposes to continue offering a $2,500 eFleet Charger Rebate for all fleet owners installing a Level 2 charger. The Company proposes supporting 90% of the forecasted charger deployments in this subsegment for a total investment of $6.8 million. Encouraging Level 2 charging for fleets improves the total cost of ownership economics, which is a key driver for fleet conversion, while also reducing grid impacts and supporting DTE Electric customer affordability.

The Company also proposes continuing offering up to a $70,000 eFleet Charger Rebate for DCFCs for approximately 30% of the forecasted charger deployments for a total investment of $20 million.

Q61. What participation criteria will DTE Electric require for the Fleet Charging segment?

A61. Participating fleet customers will need to install a qualified, networked charger (similar to the eFleet Charger Rebate program today), authorize the network provider to share charger data with DTE Electric, agree to load commitments, and commit to demand ceilings in constrained areas or for large depots to help manage grid impacts.[44] Additionally, schools will need to install vehicle-to-grid chargers to be eligible for the full $70,000 rebate.

Q62. Are there additional considerations for the TEP portfolio proposal?

A62. Yes. There are four additional considerations:

1. DTE Electric investment is designed, at the portfolio level, to:
    a. Maintain affordability benefits for all DTE Electric customers, as calculated using the BCA methodology discussed in the next section, and

[44] Data shared with DTE Electric would be used to derive utilization rates for each charger, determine if the charger is meeting uptime requirements, discern charging trends, and other purposes. Data shared with DTE Electric will not include any personally identifiable information for the EV drivers who charge on that charger.

b. Remain within the total MPSC-approved level of investment, which is being proposed at $125 million for rebates and $20 million for supporting functions over the TEP timeframe from 2025 to 2028.

2. As indicated in the explanation of multiple segments in this section, maintaining flexibility to adjust TEP programming within the approved investment limits and while maintaining affordability at the portfolio level, will be critical to successfully enable overall EV adoption during the TEP timeframe. EV's are still relatively new and evolving and DTE Electric can envision several developments like EV pricing challenges, charger technology advancement, supply chain constraints, federal incentive changes, private investment changes, and EV sales not occurring as forecasted, requiring complementary modification in TEP programming. Examples of adjustments the Company may need to make to further TEP success in achieving its goals include changing rebate dollar amounts, customer eligibility criteria, terms and conditions, and rebate volume by subsegment.

3. DTE Electric is not proposing to support the workplace charging subsegment as it is believed that there is sufficient incentive for workplaces to install chargers as an amenity to attract employees, and

4. Electric Choice customers, if they request a rebate, will receive a discounted rebate of about 35% (for example, up to $25,000 instead of $70,000 per charger) to maintain affordability benefits for all DTE Electric customers by accounting for the lower amount of rate revenue received from Electric Choice customers.

Q63. What rate book modifications is the Company proposing as part of its TEP?

Line No.

A63. The Company is proposing the following modification in rate book language as sponsored by Company Witness Willis:

- Deletion of the Charging Forward CIAC waiver in section C6.1(16) of Section C – Part I, Company Rules and Regulations.

Q64. Why is the Company requesting the deletion of the Charging Forward CIAC waiver?

A64. Consistent with providing positive rate impacts and affordability benefits accruing to all customers, DTE Electric decided, as part of its TEP, to no longer waive CIAC beyond revenue credits from the existing line extension policy. This is also in alignment with feedback received from key stakeholders. Making the rate book modification as described above will align the rate book and the TEP.

Q65. How did you support the design of the Company's EV Fast Charger Rate?

A65. Under my direction, a list of 68 known DTE Electric DCFC customers was generated and provided to Company Witness Willis. This list was initially compiled using data from the Alternative Fuels Data Center,[45] and supplemented using Charging Forward participant data.

Q66. How will DTE Electric engage key stakeholders during the TEP timeframe?

A66. DTE Electric proposes to continue providing Annual Status Reports for its TEP programs.

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[45] Alternative Fuels Data Center, available at Alternative Fuels Data Center: Alternative Fueling Station Locator (energy.gov) , https://afdc.energy.gov/stations/#/analyze?region=US-MI&fuel=ELEC&ev_levels=dc_fast, and accessed December 6, 2023. Advanced filter choices included Location: Michigan, Fuel: Electric and DCFC, Station: Public and Available

Line No.

Q67. What metrics does the Company propose to track?

A67. The Company proposes to track the following metrics, by segment:

- Rebate applications filed,
- Rebate applications approved,
- Charger uptime,
- Charger utilization rate,
- On-peak and off-peak charging,
- Customer satisfaction,
- Total investment including equity-focused programs, and
- Installation cost per port, including utility make-ready investment, customer-owed contribution in aid of construction, customer make-ready, and charger costs.

These metrics will be tracked to guide necessary adjustments to program parameters to further customer affordability and overall effectiveness of the TEP. The Company will also monitor program activity and feedback to remain agile and scale its programs in accordance with its guiding principles and to successfully influence EV adoption.

III. Benefit Cost Analysis ("BCA")

Q68. What methodology was used to evaluate the TEP BCA?

A68. In the November 2022 Order in Case Number U-20836, the Michigan Public Service Commission requested that DTE Electric "*submit a full scale, well-developed, permanent Charging Forward proposal that includes a BCA.*" The Commission additionally stated that "*the requirement of a BCA should not be interpreted as a requirement that all pilots be financially solvent at the time they* *are proposed (although that is preferable) but that when weighing costs versus benefits for a full-scale program, benefits outweigh costs over the duration of the program.*" As such, DTE Electric developed a robust BCA for the TEP that can be evaluated by segment and for the whole TEP portfolio. This BCA shows that the TEP portfolio provides net benefits to customers over its duration.

DTE Electric used the net present value ("NPV") of the revenue requirement assessed for the TEP programs as the BCA test for the TEP. Revenue requirement is the required additional revenue that DTE Electric needs to collect from customers to recover the cost of administering the TEP programs. When the TEP programs produce positive revenue requirement NPV, customers will end up, all things equal, paying higher electric rates. Conversely, when the TEP programs produce negative revenue requirement NPV, the TEP provides an offset to electric rates.

Q69. What are the key assumptions incorporated in the BCA analysis?

A69. The revenue requirement analysis takes the following elements into consideration, segmented by their effects, where (+) means they are adding rate pressure, whereas (-) means they are providing rate relief:

- (+) utility-owned UMR investment for rebated chargers,
- (+) rebates for chargers,
- (+) supporting function costs (for portfolio-level BCA only),
- (+) energy cost of serving "qualified" additional EV load, and
- (-) electric revenue from "qualified" additional EV load.

It is important to note that the BCA only considers incremental load from rebated chargers (i.e., "qualified" additional EV load). The "qualified" additional EV load occurring on TEP-supported chargers – and accounted for in the BCA – is only about 10% of the total expected EV load through 2030.

The rebated charger utilization rates used for the BCA are listed by charger type and customer segment in the table below:

Table 10 Charger Power and Utilization Rate by Customer Sub-segment and Charger Type

Charger Type	Customer Sub-Segment	Utilization Rates[46]
Level 2 12kW	SFH	2%
	MUD (LI / all other)	6% / 9%
Level 2 19kW	Workplace	1%
	Other fleet	7%
	Destination	8%
DCFC 60kW	School bus	4%
DCFC 150kW	Transit bus	14%
	Workplace	<1%
	Other fleet	5%
	On-route (disadvantaged community & rural / all other)	2% / 4%
	Destination	1%

For additional conservatism, the BCA assumes a constant utilization rate, despite the utilization rate likely increasing over time, especially in segments where chargers serve multiple vehicles, such as on-route DCFCs. For most segments, the utilization rate used in the BCA is the average across the four TEP program years as output from the segment assessment model, discussed above. For a few other

[46] Utilization rates used in the BCA are outputs from the market assessment process

segments, utilization rates were chosen using Charging Forward data instead. For example,

- Low-income MUDs and on-route DCFCs in DACs used the lower-end of a range of utilization rates from recent Charging Forward data, and
- Other fleet DCFCs used a utilization rate in line with experience from eFleet Advisory Services.

The energy cost of serving "qualified" additional EV load was calculated for each customer segment as an annual weighted average derived from hourly wholesale power price forecasts, consistent with the Company's 2022 Integrated Resource Plan filing (Case No. U-21193 Order dated July 26, 2023). Electric revenue from "qualified" additional EV load was calculated based on electric tariff rates for EV customers in their applicable rate classes. The 2024 values for electric tariff rates and the cost of energy values by customer segments are listed in the tables below:

Table 11 2024 Values for Electric Tariff Rates

Input	$/kWh	Source
SFH charger revenue	0.1502	Weighted average of residential rates D1.11, D1.2, and D1.9[47]
All other charger revenue	0.1340	General service rate D3 (no demand charges)[48]

[47] Using EV Data Sharing pilot data (participant tariffs and split of on-peak vs. off-peak charging for the corresponding tariffs).
[48] The Company does not anticipate the 1 MW threshold waiver sunset of June 2026 to affect the BCA as the vast majority of DCFC installations will remain below the acceptable threshold. However, DTEE will address this if needed after June 2026.

Table 12 2024 Cost of Energy Values by Customer Segment[49]

Customer Segment	**Cost of Energy ($/kWh)**
Single-Family Homes	0.0411
Multi-Unit Dwellings	0.0412
Public	0.0414
Fleet	0.0385
Workplace	0.0408

The revenue requirement is calculated using standard utility financing costs and accounting treatment:

- Rebates are treated as a regulatory asset (amortized over a five-year period),
- Utility-owned UMR investments are capitalized (depreciated over a 40-year period, the expected life of the UMR equipment),
- 50/50 debt-to-equity ratio with 9.9% return on equity and 4.1% weighted average cost of debt,
- 26% income tax,
- 2% property tax, and
- Discount rate of 6.92% for NPV calculation, based on DTE Electric's currently approved pre-tax weighted average cost of capital of its total capital structure.

Q70. What are the results of the BCA analysis?

A70. The NPV of revenue requirements for all customer segments supported by the TEP are shown in the table below:

[49] Cost of energy is an annual weighted average for each customer segment. This is determined by multiplying the hourly load forecast for each customer segment by the corresponding hourly market locational marginal pricing forecast (aligned with 2022 IRP through 2042) to determine the total annual cost for that customer segment, and then that total cost is divided by the total energy consumed by that customer segment. Starting in 2043, cost of energy for all segments is assumed to grow at 2.5%.

Table 13 NPV Revenue Requirement of Proposed TEP Customer Segments

Customer Segment	**Customer Sub-Segments**	**NPV Revenue Requirement ($ millions)[50]**
SFHs	LI Level 2	-15
MUDs	LI Level 2	+2
	Non-LI Level 2	-31
Public	DAC/rural on-route DCFC	+14
	All other on-route DCFC	-3
Fleet	Transit bus DCFC	-6
	School bus DCFC	+7
	Other DCFC	-5
	Other Level 2	-37
Supporting Functions		+17
Total		-56

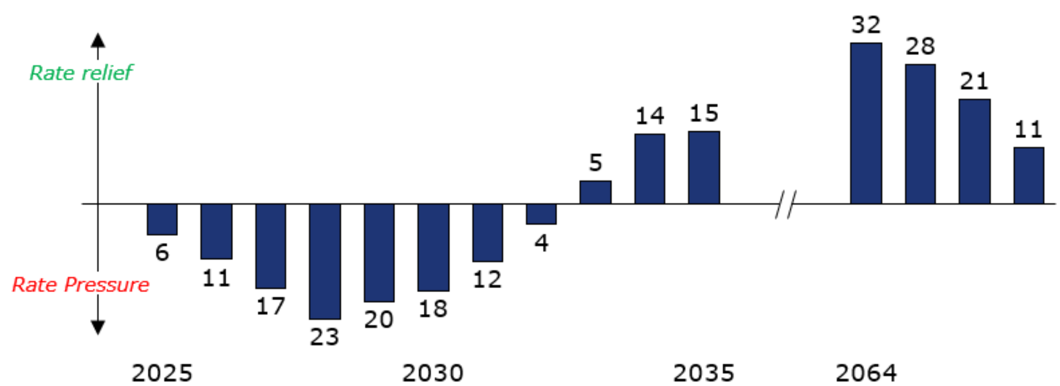
Overall, the TEP portfolio-level BCA results in $56 million of rate relief for DTE Electric customers. The segment-level revenue requirement NPVs range from $14 million in rate pressure for the DAC/rural on-route DCFC subsegment to $37 million in rate relief for the other fleet Level 2 segment. The portfolio-level BCA is the sum of the segment-level NPVs less the NPV of increased revenue requirement for supporting functions that include E&O, program administration, additional elements, and the emerging technology fund (approved in Case Number U-21297 for five years, starting in 2024, with a projected annual investment of approximately $1 million).

As shown in Figure 6 below, the annual revenue requirement initially applies rate pressure, but the TEP begins providing rate relief in 2033, increasing to a maximum of $32 million of rate relief in 2064. So, while there is rate pressure in the near-term,

[50] For net revenue requirement, + means the sub-segment or portfolio is adding rate pressure whereas - means it is providing rate relief. See above for more detail.

it is offset by future rate relief, making rebates beneficial for customers in the long run.

Figure 6 Annual Revenue Requirement from the 2025-2028 TEP Investment ($ millions)



Q71. What, in addition to the above discussion, should be considered when reviewing the BCA results?

A71. DTE Electric considers the $56 million in rate relief, calculated as a result of the proposed TEP investment using the BCA methodology described above, to be a conservative estimate, for several reasons:

1. The BCA only considers incremental load from rebated chargers; it does not take credit for any "network effects" of EV sales influenced by the TEP through reduced range anxiety. In fact, as mentioned above, the "qualified" additional EV load accounted for in the BCA is only about 10% of total expected EV load through 2030,
2. As described previously, utilization rates are held constant over the life of the electrical infrastructure serving the charger, despite likely increasing over time as EV adoption grows, and

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3. The BCA does not take credit for any revenue generated in the first year of any rebated charger's installation, despite rebated chargers coming online throughout the year that the investment occurs.

Q72. How will DTE Electric account for utility make-ready costs for all newly installed EV chargers, regardless of participation in the TEP?

A72. DTE Electric customers are expected to request new or upgraded service connections to install chargers, even if they do not participate in a TEP program. Based on the market assessment above, approximately $189 million of utility make-ready investment will be needed for utility make-ready work to connect the chargers required to support EV adoption from 2024 through 2028. From this same analysis, DTE Electric estimates that it will be responsible for approximately 85% of this investment, following DTE Electric tariff and line extension policy, with the balance coming from customers' CIAC. Therefore, the total non-CIAC UMR investment of $161 million has been included in the new customer connection portion of the budget of DTE Electric's 2023 Distribution Grid Plan (DGP) for the DGP investment timeframe of 2024 through 2028 (filed September 29, 2023, in the Case No. U-20147 docket). Non-CIAC UMR costs, for all new or upgraded service connections to install chargers, for the bridge year of 2024 ($4.7 million) and the test year of 2025 ($11.4 million) are included on page 5 , line 29 of Schedule B5.4 of Exhibit A-12.

IV. TEP Expense

Q73. What costs and accounting treatment is DTE Electric requesting for rate recovery in this proceeding associated with the TEP?

A73. TEP costs and accounting treatment the Company requests in this proceeding associated with the TEP are summarized in the table below:

Table 14 Projected TEP Program Spend in 2025 by Accounting Treatment ($, in thousands)

	Accounting Treatment			
Program Component	Capital	O&M	Regulatory Asset	**Totals**
Program Administration		1,752		**1,752**
Education & Outreach		1,500		**1,500**
Business and eFleet Charger Rebates (public, fleet and MUD segments)			16,002	**16,002**
Residential Customer Rebates (low-income single family homes only)			3,126	**3,126**
Emerging Tech Fund			1,000	**1,000**
TEP IT Capabilities	1,600			**1,600**
Total Program Spend	**1,600**	**3,252**	**20,128**	**24,980**

Q74. What are the costs for Education & Outreach?

A74. As the new fuel provider for EVs and to build off early success, the Company proposed EV E&O as a permanent offering in Case Number U-21297, and the Commission approved $1.5 million, as shown in Exhibit A-12, Schedule B5.9, line 11, column (f), on an ongoing basis for these efforts. Over 90% of surveyed stakeholders agreed that continued E&O as part of the TEP was either “important” or “extremely important” and nearly 60% responded the same for the eFleet Advisory Service, with the balance remaining “neutral” in both cases.

As its E&O efforts mature with the TEP in 2025, DTE Electric intends to roll eFleet Advisory Services under the ongoing E&O umbrella. The Company will also explore a similar service for MUDs, to ease the charger installation process for landlords. This service would partially address coordination issues stemming from landlords and Homeowners Associations not pursuing or allowing charger installations because they do not understand the incentives available or the installation process.

Q75. What are the costs for program administration?

A75. Similar to E&O, the Company proposed a permanent EV team in Case No. U-21297 and received approval in the December 1, 2023 Order. A permanent DTE Electric EV team will provide continuous, stable, and high-quality TEP administration and execution. Annual program administration costs for the TEP time frame are estimated to be about $1.8 million, as shown in Exhibit A-12, Schedule B5.9, line 12, column (f), to support labor costs for the EV team and program costs, such as EV industry knowledge sharing and the web-based rebate application subscription from PowerClerk®. The team will be responsible for everything from strategy to program execution, including facilitating EV-related federal funding opportunities for Southeast Michigan, as applicable.

Q76. What are the costs for the Emerging Technology Fund?

A76. As approved in Case No. U-21297, the $1 million annual Emerging Technology Fund allows the Company to efficiently test new technologies and prepare for widespread EV adoption in the future. The Company launched an annual grant program to enable timely funding of prudent pilots in a rapidly evolving technology environment. Organizations seeking funding are vetted via three stages of review: initial screening by the EV team, cross-functional review by other business units

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within DTE Electric, and the final review by the Emerging Technology Fund Advisory Committee that was established in March 2023.[51] Each year, the Advisory Committee convenes multiple times a year for rounds of reviews until the $1 million funding is exhausted for deserving proposals. Line 21 of Exhibit A-12, Schedule B5.9 shows $1.0 million in test period costs in column (f).

Q77. What are the costs for TEP IT capabilities?

A77. The Company is proposing an information technology investment of approximately $1.6 million, as shown in Exhibit A-12, Schedule B5.9, line 8, column (f), to build data capabilities and dashboards for the purpose of tracking and reporting. This is the majority of the approximate $2.5 million that DTE Electric estimates will be necessary to fully support the TEP programs during their four-year timeframe. This is approximately 2% of the total proposed rebates, which is in alignment with, and in some cases, even below, the benchmarked TEPs. Please see above for details on metrics proposed to be tracked.

3. <u>Customer Collection – Merchant Fees</u>

Q78. What is the purpose of your testimony regarding merchant fees?

A78. The purpose of my testimony regarding merchant fees is to support the recovery of debit and credit card payment transaction fee expenses in the Company's rates.

Q79. What are merchant fees?

[51] Members include Ecology Center, EPRI, Ford, GM, the MPSC, and Next Energy

A79. Merchant fees are the transactional costs associated with the processing of debit and credit card payments. These costs, or fees, are expenses borne by the Company and levied by the customer's debit and credit card issuer and payment processor.

Q80. What type of debit and credit cards does the Company allow customers to use?

A80. DTE Electric allows the use of all debit cards for bill payments. In addition, it allows customers to use Visa, Discover, or MasterCard credit cards. DTE Electric has restricted the type of credit cards that are allowed for bill payment to these three card issuers as they offer a lower negotiated utility transaction rate for customers using consumer credit cards.

Q81. How many DTE Electric customers used credit or debit cards as a form of payment over the last five years?

A81. The number of customers using the debit or credit payment option one or more times in a given year is shown in the table below. It has increased by 13% over the last five years, from less than 1.0 million in 2018 to over 1.1 million in 2022.

Table 15 Number of DTE Electric Customers paying with a Credit/Debit Card

2018-2022

	2018	**2019**	**2020**	**2021**	**2022**
Residential	985,417	1,047,404	1,060,122	1,092,245	1,112,592
Non-Residential	34,707	37,480	38,518	39,863	41,173
Total	1,020,124	1,084,884	1,098,640	1,132,108	1,153,765

Q82. What is the average monthly merchant fee paid by the Company?

A82. The average monthly customer merchant fee paid by the Company for residential and non-residential customers in 2022 was $0.94 and $4.72, respectively.

Q83. What measures has the Company taken to minimize merchant fees?

A83. DTE Electric continues to restrict the use of debit and credit cards for business customers with two mitigation policies that were proposed and approved by the Commission in prior rate cases:

1. In Case No. U-20162, the Company proposed excluding industrial customers on rate schedules D6.2, D8, D10, and D11 from using debit or credit cards ("Rate Blocking", implemented August 2019), and
2. In Case No. U-20561, the Company proposed limiting the use of debit and credit card payments to commercial and industrial ("C&I") customers whose aggregate annual energy bill in the preceding calendar year was less than $75,000 ("Annual $75K Blocking", implemented January 2021.)

Q84. How many DTE Energy customers were restricted from using a debit or credit card over the last five years?

A84. All customers are provided the opportunity to use a debit or credit card as a form or payment, with the exception of those customers associated with the two cost mitigation strategies described above. The number of customers restricted based on those two cost mitigation strategies over the last five years is shown in the table below:

Table 16 Total DTE Customers Restricted from Credit/Debit Card Payments[52]

	2019	2020	2021	2022	2023
Rate Blocking	271	243	191	164	116
$75K Blocking	-	-	5,328	5,238	5,882
Total	271	243	5,519	5,402	5,998

Q85. How have the non-residential cost mitigation strategies curtailed merchant fee expense?

A85. From 2016 to 2018, non-residential merchant fee expenses grew 50%, increasing from $2.1 million in 2016 to $4.7 million in 2018. From 2019 to 2022, non-residential merchant fee expense decreased by 22%, from $5.4 million in 2019 to $4.2 million in 2022, as shown in line 3 of Exhibit A-13, Schedule 5.7.1, page 2, columns (b) and (e), respectively. The reduction in non-residential merchant fees since 2019 is attributed to the implementation of the two cost mitigation strategies described above.

Q86. What does the Company forecast for merchant fees in the projected test period?

A86. The Company forecasts and seeks recovery of $12.29 million for merchant fees in the projected test period, as shown in line 5 of Exhibit A-13, Schedule C.5.7.1, page 1, column (g).

Q87. How did the Company develop the merchant fee forecast?

[52] The blocked customers include DTE Gas customers in the totals since this is not separated in the reporting system.

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A87. The Company calculated a 2023 forecast, as shown in Exhibit A-13, Schedule C5.7.1, page 2, column (g), line 4, from September 2023 year-to-date actuals and three months forecast. As described above, total merchant fees have decreased in recent years due to the non-residential cost mitigation strategies implemented in 2019 and 2021. However, now that both strategies have been in effect for over one year, the Company anticipates merchant fees to level off in 2023 and not further decrease. The two-year customer count growth of 0.5% was applied to the total 2023 merchant fee expense in column (g) to develop the 2024 and 2025 forecast, as shown in columns (h) and (i), line 4 of the same exhibit.

Q88. How did the Company calculate the customer count growth rate?

A88. The company used the 2023, 2024 and 2025 customer counts in Exhibit A-15, Schedule E6, page 1, as detailed in the table below, to calculate the growth rate used to forecast 2024 and 2025 merchant fees.

Table 17 Customer Count Growth Percentage Calculation

Customer Type	Column (s)	2023 (Line 6)	2024 (Line 7)	2025 (Line 8)	2 Year Growth
Residential	(b)	2,055,641	2,064,797	2,074,827	0.5%
Non-Residential	(c) to (e)	215,031	216,100	217,086	0.5%

4. Advanced Customer Pricing Pilot and Full Time of Day Rollout

Q89. What is the role of evaluation, monitoring and verification (EM&V) in the Advanced Customer Pricing Pilot Program (ACPP) for 2022 and the amount sought for recovery?

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A89. The role of EM&V during the ACPP pilot supported administering participant surveys and ensuring that evaluation and analysis of this data to provide compelling, comprehensive and insightful information as the Company progressed toward a full TOD rollout. Information included optimal communication channels to reach customers, the most useful tools to provide (such as on-peak/off-peak usage graphs on the website), and content most impactful for the welcome kit (such as tips to save energy on the new rate). As shown in line 5 of Exhibit A-13, Schedule C5.9.2, column (e), DTE Electric is seeking to recover $0.172 million of O&M expenses related to EM&V. Authorization to defer ACPP project costs to a regulatory asset was provided in Case No U-20162.

Q90. What is the role of Customer Outreach in the full TOD rollout?

A90. Customer Outreach communicated the transition to full TOD rollout to ensure that all residential electric customers were informed that their base rate would be changed to a new TOD rate in March 2023.

Q91. What is the total O&M expense for Customer Outreach that DTE Electric is seeking to recover?

A91. DTE Electric is seeking to recover $2.497 million of O&M expenses related to Customer Outreach for the full TOD rollout. The calendar year 2022 expenses are $2.044 million and 2023 expenses are $0.453 million. As explained further by Witness Uzenski, these expenses have been approved by the Commission for deferral and amortization over a period that includes the projected periods in this proceeding, as detailed on Exhibit A-13, Schedule C5.9.2, line 10.

Q92. Why is $2.497 million of O&M expense needed for Customer Outreach?

A92. Based on lessons learned from the Advanced Customer Pricing Pilot, DTE Electric prepared customers for the upcoming change in their rate by sending a series of communications via multiple channels. The majority of communications were sent prior to the full TOD rollout in March 2023 and informed and educated customers about their new rate and provided tips for savings on a TOD rate. The Company conducted message testing with research and focus groups to ensure that all communications developed were both easy to understand and engaging. The Company also produced the following two videos as part of its outreach strategy:

- What a customer needs to understand about the new rate; and
- How to save money on the new rate by shifting usage to non-peak times and tools to help manage usage.[53]

5. Electric Regulated Marketing Operations & Maintenance Expense

Q93. What does Electric Regulated Marketing O&M expense include?

A93. Electric Regulated Marketing O&M expense includes the following areas:

- Major Account Services, which manages new and existing customer relationships for C&I customer classes,
- Electric Marketing, which manages marketing campaigns to educate customers, develops new product and service offerings, and performs project management,
- Economic Development, which seeks to stimulate local economic growth and activity, including job growth through business attraction and expansion,

[53] Video on how to save money on the new rate - Time of Day 3 p.m. - 7 p.m. | Products | DTE Energy, available at https://solutions.dteenergy.com/dte/en/Products/Time-of-Day-3-p-m---7-p-m-/p/TOD-3-7, accessed on January 5, 2024

- The Demand Response Portfolio costs, supported by Company Witness Farrell
- Charging Forward O&M expense, explained above, and
- Amortization of the Charging Forward regulatory assets, supported by Company Witness Uzenski.

Q94. What are the Electric Regulated Marketing O&M expenses for the historical period?

A94. As shown in line 15 of Exhibit A-13, Schedule C5.9, column (e), Electric Regulated Marketing total O&M expense for the adjusted 2022 historical test period was $20.5 million.

Q95. What is the total Electric Regulated Marketing O&M expense for the projected test period that DTE Electric is seeking to recover?

A95. As shown in line 15 of Exhibit A-13, Schedule C5.9, column (k), DTE Electric is seeking to recover $32.2 million of Electric Regulated Marketing O&M expense in the projected test period.

Q96. What is driving the change between the historical period and the projected test period?

A96. DTE Electric is proposing an increase of $11.62 million based on the following changes to the historical 2022 Electric Marketing O&M expense.

1. EV Program O&M expense of $3.25 million, as shown in column (i), line 10 of Exhibit A-13, Schedule 5.9;

2. $2.96 million related to Demand Response ("DR") programs, as supported by Company Witness Farrell and shown in line 9 of the same exhibit;
3. Charging Forward regulatory asset amortization of $3.51 million, as supported by Company Witness Uzenski and shown in line 11 of the same exhibit; and,
4. Inflation for 2023, 2024 and 2025 in the amount of $1.9 million, as shown in columns (f) through (h), line 15 of the same exhibit.

The majority of the increase ($6.8 million) is driven by the Company's EV programs, which are either proposed in this case and justified above ($3.25 million) or already approved in prior cases and seeking regulatory asset amortization ($3.51 million). Another $2.96 million of the increase is due to demand response programs and justified in the instant case by Company Witness Farrell.

The remaining $1.89 million is based on assumed labor and material annual inflation adjustment factors of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025, as supported by Company Witness Uzenski.

Q97. What are your conclusions regarding the level of Electric Regulated Marketing O&M expense for the projected test period?

A97. The Electric Regulated Marketing O&M expense is reasonable, prudent, and necessary to support the programs proposed by the Company in the instant case, to maintain the existing level of customer support to C&I Major Account Services customers, to support the Company's economic development activities, and to educate all customers on Company offerings.

Q98. What are your thoughts on the level of DTE Electric's historical and projected capital, regulatory asset, and O&M expenses contained in your testimony, overall?

A98. DTE Electric has been reasonable and prudent in past capital and O&M expenses, and I anticipate this to continue through the projected test period and beyond. I believe that DTE Electric has fully justified, as reasonable and prudent, its request for capital, regulatory asset, and O&M expenses that are set forth in my testimony and associated exhibits.

Q99. Does this complete your direct testimony?

A99. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-21534

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

Q1. What is your name, business address and by whom are you employed?

A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road, Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE Electric or Company) as the Manager of the Power Supply Strategy & Modeling team within the Generation Optimization department.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Mechanical Engineering from University of Michigan in 2005. I also received a Master of Business Administration Degree from Eastern Michigan University in 2016.

Q4. What is your work experience?

A4. After receiving my Bachelor's degree from the University of Michigan in 2005, I was employed by Consumers Energy Company (Consumers Energy). During my initial employment at Consumers Energy, I worked in their production cost modeling group where I supported the development of power supply forecasts using the PROMOD® model as the basis. In 2009, I transferred positions into the Transmission and Regulatory Strategies Department. In this role, I was responsible for monitoring and analyzing filings by the Midcontinent Independent System Operator, Inc. (MISO) at the Federal Energy Regulatory Commission (FERC). I was also responsible for forecasting future transmission and certain energy market-

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related costs in Power Supply Cost Recovery (PSCR) proceedings before the Michigan Public Service Commission (Commission or MPSC).

In 2012, I began my employment at DTE Electric within the Generation Optimization Department. In 2015, I was promoted to a Supervisor position and subsequently in October 2018, I was promoted to my current Manager position within Generation Optimization.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. Yes. I have attended Utility Rate School and the Advanced Regulatory Studies Program, both hosted by the National Association of Regulatory Utility Commissioners (NARUC) and The Institute of Public Utilities Michigan State University.

Q6. What are your current duties and responsibilities?

A6. My current responsibilities include acquisition of wholesale electric power supply to reliably and economically serve the energy requirements of the Company's customers including: optimization of the Company's generation assets, including renewable energy facilities, within the wholesale power market; management of emission allowance procurement; management of resource adequacy processes; modeling the DTE Electric generation fleet; optimizing financial transmission rights; and review and advocacy of Company recommendations regarding proposed MISO rules, regulations, and business practices.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following MPSC cases:

U-16149	Consumers Energy's 2010-2011 Gas Cost Recovery (GCR) Plan
U-16485	Consumers Energy's 2011-2012 GCR Plan
U-16924	Consumers Energy's 2012-2013 GCR Plan
U-16890	Consumers Energy's 2012 PSCR Plan
U-17097-R	DTE Electric's 2013 PSCR Reconciliation
U-17319-R	DTE Electric's 2014 PSCR Reconciliation
U-17632	DTE Electric's 2013 Renewable Energy Plan Reconciliation
U-17680	DTE Electric's 2015 PSCR Plan
U-17793	DTE Electric's 2015 Amended Renewable Energy Plan
U-17804	DTE Electric's 2014 Renewable Energy Plan Reconciliation
U-17920	DTE Electric's 2016 PSCR Plan
U-17680-R	DTE Electric's 2015 PSCR Reconciliation
U-18111	DTE Electric's 2016 Amended Renewable Energy Plan
U-18082	DTE Electric's 2015 Renewable Energy Plan Reconciliation
U-18143	DTE Electric's 2017 PSCR Plan
U-17920-R	DTE Electric's 2016 PSCR Reconciliation
U-20069	DTE Electric's 2017 PSCR Reconciliation
U-20221	DTE Electric's 2019 PSCR Plan
U-20471	DTE Electric's 2019 Integrated Resource Plan (IRP)
U-20561	DTE Electric's 2019 Main Rate Case
U-20528	DTE Electric's 2020 PSCR Reconciliation
U-18091	DTE Electric's 2021 PURPA Avoided Cost

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1	U-20836	DTE Electric’s 2022 Main Rate Case
2	U-21193	DTE Electric’s 2022 IRP
3	U-21297	DTE Electric’s 2023 Main Rate Case

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Purpose of Testimony

Q8. What is the purpose of your testimony in this proceeding?

A8. The purpose of my testimony is to calculate projected capacity related generation costs that are part of the Company's power supply costs and establish the projected wholesale market energy sales revenue net of fuel. To do this, I projected 2025 capacity-related generation costs used in the 2024 PSCR Plan (Case No. U-21425). Also, from the 2024 PSCR Plan, I projected 2025 wholesale market revenues from energy and ancillary services sales from the Company's capacity resources, and the fuel cost associated with the Company's capacity resources to calculate projected wholesale market energy sales revenue net of fuel. This information is used by Company Witness Maroun in his calculation of cost of service.

I also discuss removing the wording "making an emergency purchase" from tariff rates D1.1, D1.8, D3.3 and D5.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-26	P1	Projected 2025 PURPA Capacity-Related Generation Cost
A-26	P2	Projected 2025 PA295/PA342 Capacity-Related Generation Cost
A-26	P3	Projected 2025 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost

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Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. Section 6w(3)(a) of Act 341 requires that for rate design purposes the capacity charge include capacity-related generation costs in the Company's PSCR mechanism. What are the capacity-related generation costs included in the Company's PSCR mechanism?

A11. The Company's PSCR mechanism includes capacity-related generation costs associated with Public Utility Regulatory Policies Act of 1978 (PURPA) power purchase agreements, PA295/PA342 Company-owned renewable energy systems, PA295/PA342 renewable energy contracts, and capacity purchases.

Q12. How did the Company project the 2025 capacity-related generation costs for PURPA power purchase agreements as included in its PSCR plan filing in Case No. U-21425?

A12. Most of the Company's PURPA contracts have three rate components: fixed, operation and maintenance (O&M), and variable. Two of the Company's PURPA contracts only have a capacity component. The projections for the fixed, O&M, and capacity components were included in the capacity-related generation costs. The total projected 2025 PURPA capacity-related generation cost is $8.9 million as shown on Exhibit A-26, Schedule P1, line 12.

Q13. What costs associated with PA295/PA342 Company-owned renewable energy systems and power purchase agreements are included in the PSCR?

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A13. The portion of the cost of PA295/PA342 Company-owned renewable energy systems that is passed through the PSCR Transfer Price mechanism is the approved Transfer Price Schedule or the levelized cost of energy for the renewable energy systems. The portion of the cost of PA295/PA342 power purchase agreements (i.e., non-Company owned) that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the power purchase agreement and the contract price of the agreement.

The Transfer Price is a proxy for the incremental non-renewable capacity and energy expense that would be passed on to the customer if the renewable energy resource was not developed. The relevant statute explains that when setting the Transfer Price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, but not limited to, locational marginal pricing.

Q14. How did the Company project the 2025 capacity-related generation costs for PA295/PA342 company-owned renewable energy systems and power purchase agreements?

A14. The capacity-related generation cost for PA295/PA342 Company-owned and non-Company-owned renewable energy systems and power purchase agreements is the approved Transfer Price fixed component for each specific renewable energy system. The total projected 2025 PA295/PA342 capacity-related generation cost is $130.5 million as shown on Exhibit A-26, Schedule P2, line 39.

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Q15. How did the Company project the 2025 cost of capacity purchases?

A15. The Company included the net capacity purchase costs based on the 2024 PSCR Plan (Case No. U-21425) forecasted expense for the calendar year 2025. The expense includes the Company's net transactions within the MISO annual Planning Resource Auctions (PRA) covering the 2025 calendar year[1]. Consistent with the amount filed in Case No. U-21425, the Company is projected to sell capacity in the amount of $(1.3) million as shown on Exhibit A-26, Schedule P3, line 6.

Q16. How did the Company calculate the projected 2025 energy sales revenue net of projected fuel costs per Section 6w(3)(b) of Act 341?

A16. Section 6w(3)(b) of Act 341 requires that the revenue, net of projected fuel costs, from energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit-specific bilateral contracts be subtracted from the Company's capacity costs before calculating its capacity charge. I performed the calculation using the forecasted assumptions from the Company's 2024 PSCR Plan, Case No. U-21425. To calculate the energy sales revenue net of projected fuel costs, first the projected wholesale energy revenue from the Company's generation resources (including power purchase agreements) was determined (Exhibit A-26, Schedule P3, line 11). Next, the projected wholesale revenue associated with ancillary services provided by the Company's generation resources was determined (Exhibit A-26, Schedule P3, line 14). Finally, all fuel expenses associated with the wholesale energy and ancillary services were determined (Exhibit A-26, Schedule P3, line 20) and subtracted from the projected wholesale revenues (Exhibit A-26,

[1] MISO annual resource adequacy auctions cover the Planning Year from June 1st – May 31st. The 2024/25 Planning Year auction covers January 1st – May 31st, 2025 and the 2025/26 Planning Year auction covers June 1st – December 31st, 2025.

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Schedule P3, line 15) resulting in the energy sales revenue net of projected fuel costs (Exhibit A-26, Schedule P3, line 22).

Q17. What is the projected revenue associated with wholesale energy sales from the Company's generation resources in 2025?

A17. The Company receives wholesale energy revenues from the MISO wholesale energy market for the electricity produced by its generation assets. The wholesale energy revenues forecasted for all Company assets (including PPAs) in the Company's 2024 PSCR Plan (U-21425) was calculated to be $2.180 billion shown on Exhibit A-26, Schedule P3, line 11. This was done by summing the hourly generation multiplied by the corresponding hourly market price.

Q18. Is the Company projecting any off-system energy sales or sales under unit specific bilateral contracts in 2025?

A18. No. These values are shown as zero on Exhibit A-26, Schedule P3, line 12 and 13.

Q19. What is the projected ancillary services revenue from the Company's generation resources in 2025?

A19. The Company receives wholesale revenue for providing the following ancillary services: regulation reserves, spinning reserves, supplemental, and short-term reserves (all settled via MISO's energy and ancillary services market). The Company's 2024 PSCR Plan projected that Company's generation resources would generate $4.3 million of wholesale revenue associated with regulation, spinning, and supplemental reserves. The projected wholesale ancillary services revenues from the Company's generation resources in 2025 are shown on Exhibit A-26,

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Schedule P3, line 14. Schedule 2 Reactive Ancillary Services Revenue is no longer included since FERC approved elimination of compensation for Schedule 2 in 2023.

Q20. What is the total projected wholesale energy sales revenue including ancillary services in 2025?

A20. The total projected wholesale energy sales revenue including ancillary services in 2025 is $2.184 billion as shown on Exhibit A-26, Schedule P3, line 15.

Q21. What is the projected fuel cost required to generate the projected wholesale energy and ancillary services sales from the Company's generation resources in 2025?

A21. The projected fuel cost required to make the energy and ancillary services market sales is projected from the generation in the 2024 PSCR Plan and includes: fuel, variable component of power purchase agreements, and the variable component of renewables (based on removing the fixed component of the MPSC-approved transfer prices from the overall transfer price). Total projected fuel costs for the Company's generation fleet are $1,201 million as shown on Exhibit A-26, Schedule P3, line 20.

Q22. How did you address the MISO market administrative costs associated with Schedule 17 as well as chemical and emission expenses?

A22. I removed the Schedule 17 costs from being included in the fuel costs in accordance with the Commission Order in Case No. U-20836. However, I believe that these costs should be included in fuel costs under Section 6w(3)(b) of Act 341, because

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they are directly attributable to "injections" of energy into MISO and must be incurred to effectuate the generation sales. I also removed the chemical and emission costs which amount to $28.4 million in accordance with the Commission Order in Case No. U-21297, while I disagree with this direction. Chemical and emission costs are required to produce the energy from a significant amount of the Company's generation assets and the revenues associated with the energy sales would not be possible without these expenses. To give the "benefit" of the energy sales to customers being assessed a capacity charge per the State Reliability Mechanism (SRM) without including all the attributable costs required to produce the energy and make the sales is not fair to the Company's PSCR customers who end up paying those extra costs, thus subsidizing customers on the SRM Capacity Charge. The SRM was put in place to ensure that all electric suppliers were planning for reliable energy supply, and it also allows for electric choice customers to obtain temporary capacity from the incumbent utility while continuing to receive energy from their alternative electric supplier. This flexibility already allows electric choice customers to have the benefit of short-term market trends without committing to the long-term investments needed for reliability, it should not inappropriately burden the Company's full-time customers by providing additional subsidies to electric choice customers.

Q23. How does the Company intend to handle any reconciliation of previous year variance of wholesale energy sales revenue net of fuel costs?

A23. The Company currently has no electric choice customers being assessed a capacity charge, thus no reconciliation with any customers has been previously done. The Company files a reconciliation exhibit in the annual PSCR Reconciliation case that would be used for any reconciliation adjustment if a customer were to be charged the SRM.

Q24. What is the Company's projected wholesale energy sales revenue net of projected fuel costs per Section 6w(3)(b) of Act 341 for 2025?

A24. The total projected 2025 wholesale energy sales revenue of $2.184 billion, net of $1.201 billion in fuel costs equates to $0.983 billion wholesale energy sales revenue net of fuel costs as shown on Exhibit A-26, Schedule P3, line 22. This amount was provided to Company Witness Maroun to develop his capacity related cost of service.

Q25. Why are you proposing to remove "making an emergency purchase" from rates D1.1, D1.8, D3.3, and D5?

A25. This language is not needed as any emergency interruptions are covered under other language within these rates, specifically, "maintaining system integrity" and "when available system generation is insufficient to meet anticipated load." The Company does not make any specific emergency purchases as energy transactions are handled through MISO during emergency declarations.

Q26. Does this complete your direct testimony?

A26. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL S. COOPER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL S. COOPER

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Michael S. Cooper (he/him/his). My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy Company (DTE Energy).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Business Administration Degree with a major in accounting and finance from the University of Toledo in 1994. I received a Master of Arts Degree in educational administration from Michigan State University in 1997.

Q4. What is your current position and work experience?

A4. My current position is Director of Compensation, Benefits & Wellness. I joined DTE LLC full time in 2008 and held positions with increasing responsibility in Human Resources. In 2012, I became the Manager of Compensation and assumed my current position in 2017. Prior to joining DTE LLC, I was employed by Manpower as an on-site Staffing Program Manager and in other related positions for Visteon Corporation. I was previously employed at Robert William James & Associates as a recruiter with an emphasis in accounting and finance related positions.

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Q5. What are your current responsibilities as Director of Compensation, Benefits & Wellness?

A5. As Director of Compensation, Benefits & Wellness, I have overall responsibility for the design, implementation, and administration of DTE Energy's compensation and employee benefits related policies and practices.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-18255	2017 DTE Electric General Rate Case
U-18999	2017 DTE Gas General Rate Case
U-20162	2018 DTE Electric General Rate Case
U-20561	2019 DTE Electric General Rate Case
U-20642	2019 DTE Gas General Rate Case
U-20836	2022 DTE Electric General Rate Case
U-20940	2021 DTE Gas General Rate Case
U-21291	2024 DTE Gas General Rate Case
U-21297	2023 DTE Electric General Rate Case

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. My testimony will present an overview of employee compensation practices and benefit expense for DTE Electric for the 2022 historical test period and the 12 months ended December 31, 2025, projected test period. Specifically, I will:

1. Provide support for the Company's projected pension costs, other post-employment benefits costs (OPEB), active employee health care costs and the costs of other employee benefits;
2. Support the Company's labor cost escalation assumptions used in Company Witness Uzenski's development of the composite inflation factors for the projected test period;
3. Provide an overview of the Company's compensation philosophy for non-represented employees and the role that the Company's incentive plans play in the overall reasonableness of its total compensation policies, including an analysis of salaries for non-represented positions as of December 31, 2022, relative to the market medians for comparable positions;
4. Describe the components of the Company's short-term and long-term incentive compensation plans and support the inclusion of such cost in the Company's revenue requirement, exclusive of the costs related to DTE Energy's Top Five Executive Officers; and
5. Demonstrate that the quantifiable customer benefits of the Company's incentive compensation plans exceed the corresponding expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

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In summary, my testimony will support the reasonableness and validity of the projected employee benefits and compensation expense to be incurred by DTE Electric for the projected test period.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-13	C5.11	Projected Operation and Maintenance Expenses - Employee Pension and Benefits
A-13	C5.11.1	Willis Towers Watson Healthcare Trend Projection
A-13	C5.11.2	PwC 2024 Medical Cost Trend
A-13	C5.11.3	Constant Dollar Active Healthcare Adjustment
A-13	C5.12.1	Projected Operation and Maintenance Expenses – Pension Cost - Qualified
A-13	C5.12.2	Projected Operation and Maintenance Expenses - Other Post-Employment Benefits (OPEB)
A-21	K1	Employee Compensation Market Analysis: December 31, 2022
A-21	K2	2023 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Electric Company
A-21	K3	2023 Annual Incentive Plan and Rewarding Employees Plan Metrics: Nuclear Generation
A-21	K4	2023 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Energy Corporate Services LLC

A-21	K5	2023 Long-Term Incentive Plan Performance Shares Metrics
A-21	K6	2023 Incentive Plans Cost/Benefit Analysis

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by Witness Uzenski.

<u>EMPLOYEE PENSION COSTS</u>

Q10. What are pension costs?

A10. Pension costs are those costs related to retirement benefits for the employees of DTE Electric that are eligible to participate in the Company's defined benefit pension plans. The Company's defined benefit pension costs are recognized under Financial Accounting Standard Board's Accounting Standard Codification (ASC) Section 715-30 (ASC 715-30). Costs for the Company's Savings Plan and other defined contribution benefits are recognized separately.

Q11. What are the components of pension costs?

A11. Pension costs are measured at the beginning of each fiscal year, under ASC 715-30, and include the following four pension cost components:

<u>Service Costs:</u> Service Costs represent the pension benefits earned by active employees, on a present value basis, during the current period. Service Costs are measured based on the expected benefits to be paid based on actuarial assumptions

including current and projected salaries, expected employee turnover, and life expectancy.

Interest Costs: Interest Costs are the increase in the Projected Benefit Obligation (PBO) due to the passage of time during the current period. The PBO is the actuarial present value of benefits attributable to the pension benefit formula and service accrued to date discounted back to current dollars at a discount rate selected at the prior year-end. A discount rate of 5.19% was used in determining the PBO as of December 31, 2022. Measuring the PBO as a present value at the beginning of each fiscal year requires the accrual of an interest cost for the current period at a rate equal to the prior year's discount rate. The discount rate used in measuring Interest Costs, as well as Service Costs for the 2022 historical test period, was 2.91%, based on the interest rate environment at the end of 2021, and projected benefit payments from the pension plan matched against a yield curve of corporate bond rates, rated AA or higher, provided by Aon, the Company's independent actuarial firm. This was then reviewed by PriceWaterhouseCoopers (PwC), the Company's independent accounting firm in connection with its audit of the Company's financial statements as filed with the Securities and Exchange Commission (SEC). The 5.19% discount rate used for determining Interest Costs and Service Costs for the projected test year is based on the discount rate as of December 31, 2022, which reflects the traditional assumption that high-quality corporate bond yields at the end of 2022 will remain unchanged from the rates prevailing at the end of the historical test year.

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Expected Return on Assets: The Expected Return on Assets (ERoA), which is an offset to pension costs, is an estimate of the expected investment return during the current period, on the Market Related Value of the assets invested in the pension trust at the beginning of the year adjusted for any expected funding activity and projected benefit payments for the year. While actual year-to-year investment returns can vary significantly, the ERoA is determined based on forward-looking long-term financial market expectations to avoid large swings in pension costs based on short-term investment performance. DTE Electric's expected annual return was 6.80% during the 2022 historical test year, as developed by NEPC LLC, the Company's independent investment consulting firm, and reviewed by PwC in connection with its audit of the Company's financial statements as filed with the SEC. The ERoA is 7.60%, 7.90% and 7.80% in 2023, 2024 and 2025, respectively. The increase in the ERoA is due primarily to an increase in the forward-looking long-term capital market assumptions that reflects the impact of the negative market performance in 2022. These ERoAs are based on market conditions and pension funding status as of late 2022.

Amortizations: In addition to current period costs described above, pension costs also include the effect of the delayed recognition of prior period costs. This includes Unrecognized Gains and Losses and Prior Service Costs. Unrecognized Gains and Losses are changes in the amount of either the PBO or the plan's assets resulting from experience different from that assumed in actuarial assumptions. Most notably, since discount rates and return on assets assumptions are based on either point in time measurements or long-term estimates of expected returns, differences arise whenever a change is made in the discount rates or when the actual

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asset returns differ from long-term expectations. These gains and losses are deferred and the amount of the unrecognized balance in excess of a corridor equal to 10% of the greater of the PBO or the Market Related Value of assets is amortized based on a period equal to the average remaining service life of employees covered by the plans. Prior Service Costs arise from pension plan amendments that affect future benefits. When a plan provision is changed that will affect future benefit payments for existing employees or retirees, the resulting change in the PBO liability is amortized over the average remaining years of service life of the active employees.

Q12. What is the level of pension funding reflected in the projected pension costs?

A12. Based on the pension funding status on December 31, 2022, the Company is not expected to fund pension plans in 2023, 2024 or 2025. While there is no planned funding of DTE Electric's pension trust, $50 million of pension assets related to the DTE Gas Non-Union pension trust were transferred to DTE Electric's pension trust assets in November 2023 in exchange for cash consideration. The reasons for these transfers are explained by Witness Uzenski.

Q13. How are pension costs expected to change between the historical test year and the projected year?

A13. As summarized on Exhibit A-13, Schedule C5.12.1, the Company's pension costs are projected to decrease from $90.987 million during the historical test year, which includes the one-time cost of $64.798 million related to settlement charges recognized in 2022, to $53.993 million for the projected test year. After adjustments for the portion of pension costs capitalized and transferred, the Company's projected pension expense is $32.273 million, as reflected on Exhibit A-13, Schedule C5.12.1, line 19.

Q14. Is the pension expense included in the Company's proposed revenue requirement?

A14. No. Witness Uzenski sponsors the Company's proposal to continue to defer the projected pension expense to the accumulated regulatory liability as initially authorized by the Commission in its Order in Case No. U-20836. Thus, the projected pension expense is not reflected in the Company's proposed revenue requirement and the pension expense is eliminated on line 20 of Exhibit A-13, Schedule C5.12.1.

OTHER POST-EMPLOYMENT BENEFITS (OPEB) COSTS

Q15. What are OPEB Costs?

A15. OPEB costs relate to the provision of retiree medical, dental, prescription drug and life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting Standard Codification (ASC) section 715-60. Similar to ASC 715-30, OPEB costs are determined under ASC 715-60 at the beginning of each fiscal year.

Q16. What are the cost components of OPEB?

A16. OPEB has the same basic cost components as pension costs. They are:

Service Costs: Service Costs are the portion of the expected post-retirement benefit obligation, on a present value basis, attributable to employee participation service during the current period. Service Costs reflect actuarial assumptions of employee turnover, age at retirement, and expected longevity. Service Costs also depends on the estimated costs of providing these benefits after the employee's retirement and, therefore, is impacted by both current medical cost levels and expected medical cost inflation.

Interest Costs: Interest Costs are the costs arising from the current period interest on the discounted Accumulated Post-Retirement Benefit Obligation (APBO). The APBO was discounted to today's dollars based on a discount rate of 2.91% as of December 31, 2021, which was also used to determine Interest Costs in 2022. The discount rate used to measure the APBO as of December 31, 2022, was 5.19%, which was also used to determine the Interest Costs on the APBO during the projected test year. The discount rate of 5.19% was determined based on the interest rate environment at the end of 2022, as determined in a similar manner to the measurement of the Company's pension costs, as described above.

Expected Return on Assets: The Expected Return on Assets (ERoA), which is an offset to OPEB costs, based on the forward-looking long-term financial market expectations to avoid large swings in OPEB costs based on short-term investment performance. The ERoA was 6.40% during the historical test year and is 7.20%, 7.30% and 7.30% in 2023, 2024 and 2025, respectively. The increase in the ERoA is primarily due to an increase in the forward-looking long-term capital market assumptions that reflects the impact of negative capital market performance in 2022. These assumptions are based on market conditions and funded status at the end of 2022.

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Amortizations: This cost component includes the amortizations related to deferred Gains and Losses as well as Prior Service Costs. Accumulated gains and losses, outside the 10% corridor, as described for pension costs, are amortized over the current estimated remaining service life of active participants. Prior Service Costs are amortized over the estimated remaining service life of active participants, at the time of the last plan change, to the age at which these employees are fully eligible for the benefits.

Q17. How are these OPEB costs expected to change between the historical test year and the projected test year?

A17. As reflected on Exhibit A-13, Schedule C5.12.2, the Company's OPEB costs are projected to increase from negative $36.661 million in the historical test year to negative $14.459 million during the projected test year. After adjustments for the portion of OPEB costs transferred and capitalized, the net OPEB expense is projected to be negative $8.395 million, as shown on Exhibit A-13, Schedule C5.12.2, line 17.

Q18. Is the negative OPEB expense included in the Company's proposed revenue requirement?

A18. No. Witness Uzenski sponsors the Company's proposal to continue to defer to the projected negative OPEB expense to the accumulated regulatory liability. Thus, the projected OPEB expense is not reflected in the Company's proposed revenue requirement and the negative OPEB expense is eliminated on line 18 of Exhibit A-13, Schedule C5.12.2.

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Q19. Did the Commission address the OPEB regulatory liability in its Order in Case No. U-21297?

A19. Yes. In its Order in Case No. U-21297, the Company's most recent rate case, the Commission adopted a seven-year amortization of the Company's OPEB regulatory liability as of December 31, 2022, which resulted in an annual amortization of $18.300 million that reduced the Company's revenue requirement (Case No. U-21297, Order, pp 223-224). This annual amortization of $18.300 million is reflected on Exhibit A-13, Schedule C5.12.2, line 19, as a reduction to OPEB expense and is also reflected on Exhibit A-13, Schedule C5.11, line 3.

Q20. Has DTE Electric previously externally funded its OPEB costs?

A20. Yes. DTE Electric has generally funded the OPEB costs included in the Company's revenue requirement adopted by the Commission in previous orders through a Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal Revenue Code Section 401(h) trust.

Q21. Will the Company externally fund its OPEB liability in the future?

A21. No. Since the Commission approved the Company's proposal in Case No. U-20836 to continue the deferral of the projected negative OPEB expense, initially approved by the Commission in Case No. U-17767, the Company's current and projected revenue requirements do not include any OPEB expense and thus there is no obligation for the Company to externally fund its OPEB liability.

<u>NEW HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS</u>

Q22. What is the New Hire VEBA?

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A22. The New Hire VEBA expense on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the plans that are offered in lieu of the traditional retiree healthcare plan for eligible employees, as adjusted for the portion of those costs that are capitalized. Because the New Hire VEBA is generally offered in lieu of the Company's traditional retiree healthcare plan, which is closed to most new participants, this increase in costs is offset by avoided OPEB costs.

Q23. What are the components of the Company's New Hire VEBA costs?

A23. The Company's New Hire VEBA costs consist of contributions generally made for newly hired employees after 2012. Specifically, the Company contributes $4,000 on behalf of non-represented and certain Local 17 employees in their year of hire, as prorated for month of hire, and $4,000 every year thereafter. For employees represented by Local 223, the Company makes a payment of $1,650 on their first service anniversary and contributes $40 per week thereafter. In 2022 the average Company contribution for Local 223 employees was $2,177.

In addition, the Company recognizes a true-up of the estimate of the Company's liability for contributions for non-represented and Local 17 employees that reflects final determinations of plan eligibility and any forfeitures by employees that leave the Company before the end of the 10-year vesting period. No such true up is required for Local 223 employees because payments are made through the bi-weekly payroll process and the Company doesn't receive any benefit from employee departures.

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Q24. What adjustments are you proposing to the Company's New Hire VEBA expense?

A24. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 4, I am proposing two adjustments to New Hire VEBA expense. The first, which is reflected on column (c) represents a normalization of the Company's recorded 2022 New Hire VEBA expense and the second, which is reflected in column (h) represents the projection of this expense through the end of the projected test year.

Q25. Why is a normalization adjustment required for the Company's recorded 2022 New Hire VEBA expense reflected on Exhibit A-13, Schedule C5.11, page 2, line 4, column (c)?

A25. In 2022, the Company recognized an unusually high true-up adjustment related to the New Hire VEBA costs recognized in 2021 compared to the actual funding requirement for 2021. Specifically, the 2021 true-up reflected as a reduction to the Company's New Hire VEBA expense, which after reduction for the portion capitalized, was $1.336 million, whereas the average of the five prior years true-up adjustments on a similar basis was only $0.310 million. There were two primary drivers of the large increase in the true-up recognized in 2022 related to 2021. First, due to historically low levels of employee turnover during the COVID-19 pandemic in 2020 there was a reduction in the number of new hires eligible to participate in the plan in 2021. Second, as the economy transitioned out of the pandemic in 2021 and employee turnover increased, there was a substantial increase in the forfeitures of accumulated balances by employees that left the Company before they were vested in the plan. These two factors resulted in an unusually large true-up in 2022 that is non-recurring. Accordingly, the Company's 2022 recorded New Hire VEBA

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expense should be increased by $1.027 million, which represents the excess of the 2021 true-up over the average of true-ups recognized in the prior five-years.

Q26. What is the basis for the projected increase in the New Hire VEBA expense?

A26. The New Hire VEBA expense is projected to increase from the normalized 2022 expense of $7.707 million to $9.847 million in the projected test year. This increase reflects the growth in the number of plan participants due to new hires.

Q27. How was the projected New Hire VEBA expense developed?

A27. The projected New Hire VEBA expense was developed based on the number of active participants in the plans as of December 31, 2022, which was increased by the number of expected new participants based on the most recent five-year average of actual new plan participants prorated for the assumption that the new participants would be added evenly throughout the year (i.e., divided by two). The average plan participants for each year were costed-out based on the Company's required contributions for each plan, as described above, to determine the projected gross cost for each plan. The amount for the non-represented employees and employees represented by Local 17 was then reduced by the five-year average of employee forfeitures for those plan participants that left the Company before they were vested in the plan. Total costs for the projected test year are projected to be $15.320 million, which is reduced by 35.7% to recognize the portion of costs to be capitalized, resulting in net New Hire VEBA expense of $9.847 million. This represents an average annual increase of 13.8%.

Q28. What is included in Employee Savings Plan expense reflected on Exhibit A-13, Schedule C5.11, line 5?

A28. The Company's Employee Savings Plan is an employee benefit plan that allows eligible employees the opportunity to contribute a certain percentage of their annual earnings that the Company matches, generally up to 6% of annual salaries and wages for non-represented employees and for most represented groups. In addition, employees hired after the Company's defined benefit pension plans were closed to new hires receive an additional Company contribution of 4.0% of their pay, although certain represented employees receive a Company contribution of 8.0% of their pay.

Q29. What adjustments are you proposing to the Company's Employee Savings Plan expense?

A29. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 5, I am proposing two adjustments to Employee Savings Plan expense. The first, which is reflected on column (c), represents a normalization of the Company's recorded 2022 Employee Savings Plan expense and the second, which is reflected in column (h), represents the projection of this expense through the end of the projected test year.

Q30. Why is a normalization adjustment required for the Company's recorded 2022 Employee Savings Plan expense as reflected on Exhibit A-13, Schedule C5.11, page 2, line 5, column (c)?

A30. The Company experienced an abnormally high level of employee resignations in 2021, which were likely driven by the transition out of the COVID-19 pandemic, that resulted in an abnormally high level of forfeitures recognized in 2022.

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Specifically, the Company recognized a reduction in its Employee Savings Plan expense arising from forfeitures, predominately due to the departure of non-vested employees in 2021 of $0.837 million, whereas the five-year average of forfeitures prior to 2022 was $0.459 million, resulting in excess forfeitures of $0.378 million. Because the elevated level of forfeitures in 2021 was the result of a once in a century pandemic, it is proper to normalize 2022 for the impact of forfeitures in excess of a normal level. The elimination of excess forfeitures results in a normalized 2022 Employee Savings Plan expense of $30.077 million as shown on page 2 of Exhibit A-13, Schedule C5.11, page 2, line 5, column (d).

Q31. How was the projected Employee Savings Plan expense developed?

A31. The projected Employee Savings Plan expense was developed based on the normalized 2022 expense escalated by the four-year average of the annual increase in the Company's Employee Savings Plan costs for the years 2017 through 2020 of 7.50%. This results in Employee Savings Plan expense for the projected test year of $37.406 million.

Q32. Why have you not included the annual percentage increase in the Company's Employee Savings Plan costs for 2021 and 2022 in the historical average annual increase?

A32. In 2021, the Company's Employee Savings Plan costs were impacted by the low level of new employees during the COVID-19 pandemic. Plus, in 2022 the Company recognized an abnormally high level of forfeitures arising from employee resignations in 2021, as the economy transitioned out of the pandemic. Accordingly, the Company's experience in both 2021 and 2022 were impacted by the same non-recurring item, to-wit, the once in a century worldwide pandemic. Since both years were impacted, both the 2021 and 2022 annual increase should be excluded from the historical annual rate of change in the Employee Savings Plan costs. This is consistent with the methodology adopted by the Commission in its Order in the Company's most recent rate case which adopted the recommendation of the Administrative Law Judge (Case No. U-21297, Order December 1, 2023, p. 191).

Q33. Why did you escalate the adjusted historical test year Employee Savings Plan expense by the average annual increase in the Company's Savings Plan costs rather than the annual increase in the Company's Savings Plan expense?

A33. Since the Company's Employee Savings Plan expense is impacted by the proportion of the costs that are capitalized, the annual changes in the Company's Employee Savings Plan expense reflects both the effect of the changes in costs and changes in the proportion of the costs capitalized. For example, the five-year average of the annual increase Employee Savings Plan expense was 6.20% for the years 2018 through 2022, but this reflects an increase in the proportion of costs capitalized from 31.3% in 2017 to 39.6% in 2022. This increase in the proportion of costs capitalized reflects the significant increase in the Company's capital expenditures over this time frame, which is assumed to remain constant through the projected test year. Therefore, under the assumption that the proportion of costs capitalized will not increase in the future, the historical average annual increase in the Company's Employee Savings Plan costs of 7.50% for the years 2017 through 2020, as described in Q32, is a more accurate measurement of the projected increase in the Company's Employee Savings Plan expense.

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ACTIVE HEALTHCARE EXPENSE

Q34. What are the healthcare benefit programs offered to active employees?

A34. The Company offers a competitive active healthcare benefits package for the attraction and retention of a skilled workforce. The components of these benefits are summarized on Exhibit A-13, Schedule C5.11 (lines 8 through 10) and consists of medical, dental, and vision benefits for active employees that are projected to increase from $50.126 million in the historic test year to $56.083 million. This increase includes the normalization of the historical Active Healthcare costs to reflect a historical average of constant dollar costs, as developed on Exhibit A-13, Schedule C5.11.3, and annual escalations for the adjusted medical plan trend of 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025, as more fully described below in Q47 through Q54.

Q35. What is the Normalization Adjustment to 2022 Active Healthcare costs as reflected on Exhibit A-13, Schedule C5.11?

A35. The year-to-year volatility of actual Active Healthcare costs makes the use of any one historical period's cost a potentially unreliable starting point in the determination of projected Active Healthcare costs. Accordingly, the adjustment of negative $1.260 million reflected on Exhibit A-13, Schedule C5.11, page 2 on line 11 of column (c), represents a normalization of the Company's actual 2022 Active Healthcare costs that is designed to eliminate the volatility of the Company's Active Healthcare costs through the quantification of the Company's historical Active Healthcare costs per employee, as adjusted for national historical healthcare cost trends. This results in an average of the Company's actual Active Healthcare costs per employee that eliminates the impact of historical healthcare cost inflation and, therefore, reflects the cost volatility due to changes in the usage of healthcare services.

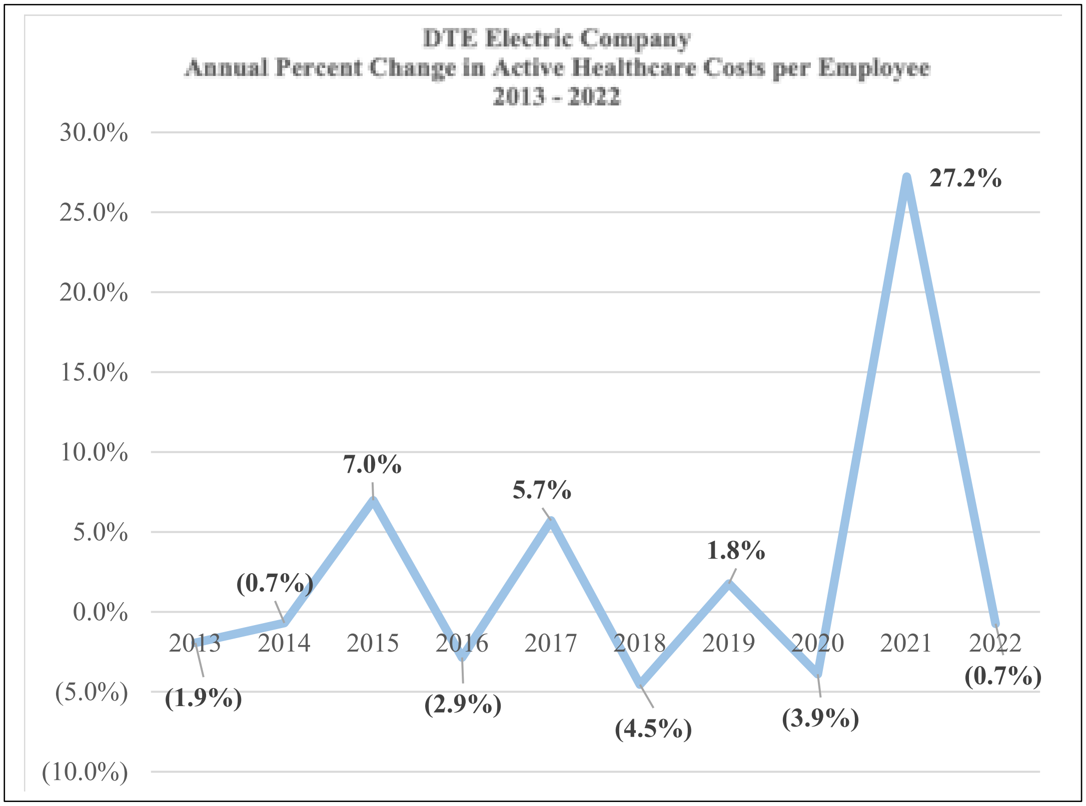
Q36. What is the basis for your conclusion that year-to-year Active Healthcare costs are volatile?

A36. The primary reason the Company's Active Healthcare costs reflect substantial volatility among years is that the Company is self-insured for about 70% of its total Active Healthcare costs. Self-insurance results in the level of Active Healthcare costs incurred by the Company being highly impacted by the mix and severity of medical treatments administered to employees and their eligible dependents in any given year. For example, in 2020 DTE Electric's medical claims related to outpatient specialty drugs decreased by almost $0.6 million, or over 25%, compared to 2019 while in 2021 claims for the same category increased by over $1.4 million or almost 90%. In addition, in 2021, inpatient care related to the treatment of COVID-19 infections increased by over $1.0 million and then declined by almost $1.2 million in 2022. Also in 2022, the Company reinstituted its healthy living requirements for employee contributions for healthcare services that were suspended during the pandemic. As a result, total employee contributions increased in 2022 by $2.3 million, which is an offset to the Company's Active Healthcare costs. This single non-recurring increase in employee contributions reduced the Company's Active Healthcare costs in 2022 by over 2.5%.

Q37. Have you quantified the degree of volatility in the Company's Active Healthcare Costs?

A37. Yes. The actual annual percentage change in the Company's Active Healthcare costs on a per employee basis, as adjusted for a one-time credit in 2018, is reflected in Table 1 below.

Table 1



This chart shows that the Company's actual Active Healthcare costs have changed relative to the prior year by as much as 27.2% in 2021 to a decrease of 4.5% in 2018, demonstrating that Active Healthcare costs can vary significantly from year-to-year. While the average percent change in the Company's Active Healthcare costs for the years 2013 through 2022 was 2.7%, the standard deviation of this average is 9.4%.

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Q38. What is the significance of this high degree of variability in the percentage change in the Company's actual Active Healthcare costs?

A38. Since the Company's actual Active Healthcare costs can be impacted by variations in usage, the effect of benefit plan design, and changes in pricing, any given year's Active Healthcare costs will likely be an unreliable basis to establish a starting point for future Active Healthcare costs. Moreover, the small sample size of the experience of the Company makes it a poor predictor of future experience. In 2022, the Company had about 3,400 employees enrolled in its self-insured medical plans, which inclusive of dependents, represented about 9,800 total participants. The total number of participants represents too small of a sample to infer that the experience over a few years will reflect the long-term trends in the Company's Active Healthcare costs. This small sample size is a key contributor to the year-to-year variability as reflected in the high Standard Deviation relative to the average.

Q39. Is there a method of normalizing the Company's historical Active Healthcare costs to determine a more reliable starting point in determining Active Healthcare costs for the projected test year?

A39. Yes. The variability in the Company's actual Active Healthcare costs can be normalized using constant dollar Active Healthcare costs on a per employee basis. This allows for the normalization of the inherent volatility in historical Active Healthcare costs through the elimination of both the impact of healthcare price level changes and changes in the level of employees.

Q40. How did you determine a constant dollar average of the Company's Active Healthcare costs on a per employee basis?

A40. Exhibit A-13, Schedule C5.11.3 reflects the Company's actual Medical, Dental, and Vision components of the actual Active Healthcare costs for the years 2018 through 2022, before the impact of the costs capitalized and transferred. These costs are divided by the simple average of employees at the beginning and end of each year to develop the Active Healthcare costs per employee. The Active Healthcare costs per employee for each year is then adjusted for the actual percent increase in medical trends, as reported by PwC on page 2 of Exhibit A-13, Schedule C5.11.2. Adjusting the Company's actual Active Healthcare costs for the overall increases in medical costs experienced by a broad universe of employers and insurance providers, as reflected in the PwC study, enables the separation of the Company's year-to-year variability that is driven by changes in utilization by the Company's employees and their dependents from changes to overall healthcare cost trends.

The adjustment of each year's Active Healthcare costs per employee produces a five-year average cost per employee on a constant dollar basis of $12,081. By multiplying this amount by the 2022 average number of employees of 6,697, a total constant dollar Active Healthcare cost of $80.911 million is generated. This represents a $2.087 million decrease relative to the Company's incurred Active Healthcare costs in 2022. This amount is adjusted for the portion of Active Healthcare costs charged to expense and results in a constant dollar normalization adjustment of negative $1.260 million, as reflected on Exhibit A-13, Schedule C5.11.3, column (m), line 16.

Q41. How has the Commission traditionally addressed cost elements that are subject to volatility?

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A41. The Commission has routinely adopted prior year's average of the ratio of uncollectibles to revenues to project the Company's future uncollectibles expense, and for DTE Gas, has used an average of historical Lost and Unaccounted for Gas volumes to project future Lost and Unaccounted for Gas expense. The difference is that in those instances the pricing is separated from the level of activity because the ratios of uncollectibles and the volumes of Lost and Unaccounted for Gas were determined first, and then those ratios are priced by applying the percentage of historical uncollectibles for projected revenue or the average Lost and Unaccounted for Gas volumes are multiplied by the projected cost of gas rate.

In contrast, for Active Healthcare costs there is no available segregation of the impact of changes in activity, as reflected in usage of health services, and the pricing of those services. Because the price of healthcare services increases each year, it would be unreasonable to predict future Active Healthcare costs based on an average of the historical Active Healthcare costs. As a result, the only means of producing a starting point for Active Healthcare costs that is normalized for changes in utilization is to develop an historical average of costs that neutralizes the impact of changes in price levels. This is what the constant dollar normalization adjustment achieves.

Q42. Are there any useful analogies to the Company's constant dollar Active Healthcare adjustment?

A42. Yes. From a broad perspective, the constant dollar Active Healthcare adjustment should be regarded as means to neutralize the inherent volatility in the Company's actual Active Healthcare costs by restating the historical costs in current dollars, much as "nominal" price levels are routinely adjusted for the effects of inflation to develop inflation adjusted "real" prices. This allows for a meaningful comparison of costs among years without the distortion of changes in price levels.

More specifically, DTE Electric has traditionally adjusted its actual annual historical emergent replacement expenditures for inflation to develop a base spending level used in developing projected costs. This approach was explicitly adopted in a DTE Electric rate case where the Commission concluded "Adding inflation to the historic five-year historical actual spend is appropriate for calculating the starting point for normalized expenditures." (Case No. U-20561, Order issued May 8, 2020, p. 86). The continued use of a five-year inflation adjusted average of Emergent Replacement Expenditures was adopted by the Commission in other recent Company rate cases (Case No. U-20836, Order issued November 18, 2022, p. 63, Case No. U-21297 Order issued December 1, 2023, p. 76).

Q43. Has the normalization of emergent replacement expenditures for historical inflation been contested in the Company's recent rate cases?

A43. Yes. The Attorney General has consistently opposed the normalization of historical emergent replacement expenditures. In the Company's most recent rate case the Attorney General claimed that the normalization of historical expenditures for inflation compounds inflationary increases and amounts to inflating forecasted capital expenditures by increasing the base used in the projections (Case No. U-21297, Order, p. 74). Based on this claim, the Attorney General proposed the elimination of the historical inflation normalization of emergent replacement

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expenditures. However, the Commission properly rejected the Attorney General's proposal and adopted the Company's historical inflation normalization of emergent replacement expenditures.

Q44. Did the Commission also address the issue of the constant dollar normalization of Active Healthcare costs in its Order in Case No. U-21297?

A44. Yes. In that case the Attorney General opposed the Company's constant dollar Active Healthcare cost adjustment. Like the Attorney General's arguments in opposition to the historical inflation normalization of emergent replacement expenditures, the Attorney General claimed the adjustment for historical healthcare increases compounded inflationary increases (Case No. U-21297, Order, p. 229). The Commission declined to adopt the constant dollar normalization in this matter, stating that the Company did not sufficiently demonstrate that the "proposed constant dollar normalization will not result in compounded inflationary pressures" (Case No. U-21297 Order, p. 232).

Q45. Does the constant dollar adjustment result in compound inflationary pressures?

A45. No. Just like the normalization of historical emergent replacement expenditures, the constant dollar Active Healthcare costs adjustment merely recasts the Company's historical Active Healthcare costs for the impact of historical medical cost escalations. This adjustment enables the development of a five-year average Active Healthcare costs per employee on basis that excludes the impact of changes in prices. The only difference between the two normalization adjustments is that emergent replacement expenditures are adjusted for overall inflation as measured by the Consumer Price Index whereas the Active Healthcare normalization adjustment is based on actual historical national medical cost trends as measured by the PwC actual medical cost increases. This difference in historical bases for escalation recognizes that overall inflation is an inappropriate measure of historical medical cost escalations. The escalation of the Company's historical Active Healthcare costs per employee for actual national medical cost increases allows the establishment of a normalized Active Healthcare costs per employee for the years 2018 through 2022, which is used to create a five-year average as a starting point to be used to project the Company's future Active Healthcare costs. Accordingly, it is inaccurate to conclude that the normalization of the Company's Active Healthcare costs per employee results in the compounding of inflationary pressures.

Q46. How is this constant dollar normalization adjustment reflected on Exhibit A-13, Schedule C5.11?

A46. The total constant dollar normalization adjustment of negative $1.260 million is allocated to the Active Healthcare cost components of Medical Expense, Dental Expense, and Vision Expense based on the proportion of the expenses for each of these categories in 2022 on Exhibit A-13, Schedule C5.11, page 2 of 2, column (c), lines 8 through 10, to determine the Adjusted Historical Test Period expenses in column (d), which is then adjusted for the projected active healthcare trend factors through the end of the projected test period.

Q47. What is the basis for your future trend factor in active healthcare costs used for the projected periods in this proceeding?

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A47. The annual unadjusted medical plan trend factors of 7.10% for 2023, 7.50% for 2024, and 7.00% for 2025, are based on projections for healthcare trends provided by the healthcare experts at Willis Towers Watson (WTW), as reflected in Exhibit A-13, Schedule C5.11.1. These unadjusted trend factors are reduced by 2.00% in 2023, 2.50% in 2024, and 3.00% in 2025 to reflect the expected savings to be realized by the Company's Wellness program. Accordingly, the active healthcare expense projections are based on the Company's 2022 normalized expense as escalated by the adjusted trend factors of 5.10% in 2023, 5.00% in 2024, and 4.00% in 2025.

Q48. How were these trend factors determined?

A48. WTW's first step is to develop the Allowed Trend, which is based on its internal guidance and represents its consensus expectation for medical and prescription drug costs. WTW developed the Allowed Trend based on its internal book of business and national survey as well as data from United States government offices and agencies, and various third-party sources, as described on page four of Exhibit A-13, Schedule C5.11.1. The Allowed Trend is adjusted for the Company's average fixed plan design leveraging to develop the future Medical Plan Trend, which is the basis of the Company's projected active healthcare costs.

Q49. What assumptions are reflected in WTW's overall trend factors?

A49. WTW's key assumptions for 2023 are described on page five of Exhibit A-13, Schedule C5.11.1. Specifically, WTW assumes that overall inflation will be between 2.50% and 4.00%. Added to the overall inflation is the incremental healthcare inflation of between 1.00% and 2.15%, which is premised on the assumption that healthcare inflation will likely revert to the historical pattern of healthcare inflation exceeding overall inflation. This assumption reflects the expectation that labor shortages in the healthcare industry will become more acute as well as the likelihood of increased pricing for long-term contracts between insurance carriers and healthcare providers. Finally, WTW expects the impact of higher utilization will add between 1.75% and 3.25% to the expected trend factors, which recognizes traditional experience in the low end assumption and the high end assumption reflects the risk that COVID-19 related disruptions in the delivery of healthcare services will lead to future increases in utilization. In sum, WTW expects the overall medical trend in 2023 will increase between 5.25% and 9.40%.

Q50. How was the 2023 trend of 7.10% developed by WTW for the escalations used by Company in its projections?

A50. As also reflected on page five of Exhibit A-13, Schedule C5.11.1, in the column labeled DTE Energy, the assumptions used in the development of the 6.60% unleveraged medical trend are detailed. Specifically, WTW assumes general inflation of 3.20%, which is based on the actual increase in the CPI through July 2023. Added to the general inflation assumption is 1.50% for the assumed incremental medical cost related inflation, which is slightly less than the midpoint of the range of 1.00% to 2.15% identified for the overall medical trend. Finally, 1.90% is added to reflect the expected change in the Company's utilization and service mix. This 1.90% addition for the impact of expected increase related to utilization and service mix at the Company is based on relative risk scores developed by Merative, a firm specializing in healthcare analytics, that projects that the Company's relative risk will increase by 5.30% over the next three years or about 1.70% annually. An additional 0.2% is added to the 1.70% to reflect the expected impact of the Company's increased utilization of higher cost specialty prescription drugs, resulting in a total increase due to utilization and service mix of 1.90%. A description of Merative and the support for the relative risk scores is reflected on page six of Exhibit A-13, Schedule C5.11.1.

Based on these assumptions WTW's 2023 medical trend is 6.60% before the impact of the Company's fixed plan design leveraging or 7.10% inclusive of the Company's fixed plan design leveraging.

Q51. Can you describe fixed plan design leveraging?

A51. Yes. Fixed plan design leveraging is the impact on the Company's costs of fixed cost-sharing plan design items, such as deductibles, coinsurance, copays and out of pocket maximum.

Q52. Are you aware of any corroborating sources that support the reasonableness of WTW's projections?

A52. Yes. A study released in 2023 by PwC's Health Research Institute, as reflected in Exhibit A-13, Schedule C5.11.2, projects that medical costs will increase by 6.0% in 2023 and 7.0% in 2024.

These studies support the reasonableness of the healthcare trend projections provided by WTW.

Q53. Have the projections of future medical trends relied upon by the Company in recent years been accurate?

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No.

A53. Yes. In recent years the Company's average projected medical trend rates were 5.5%, 6.1%, 5.9% and 6.7% for the years 2019, 2020, 2021 and 2022, respectively, or a four-year average of 6.1%. The actual increase in national medical costs compiled by PwC, as reflected on Exhibit A-13, Schedule C5.11.2, page 2, were 5.7%, 6.0%, 7.0% and 5.5% for the years 2019, 2020, 2021 and 2022, respectively, or a four-year average of 6.1%. In summary, the Company's projected trend rates, which were developed consistent with the method used by WTW in the trend rates reflected on Exhibit A-13, Schedule C5.11.1, have matched the actual national medical trend rates. This demonstrates that the Company's projected trend rates have been accurate predictors of actual medical trend rates.

Q54. Is the Company's recent experience a reliable basis for predicting future increases?

A54. No. The high variability of the annual percent change in the Company's actual Active Healthcare costs per employee, as reflected in Table 1 discussed in response to Q37, highlights the inherent flaw in using historical annual changes in the Company's Active Healthcare costs as basis for projecting future increases. As I previously discussed, the average annual percentage increase in the Company's actual Active Healthcare costs for the year 2013 through 2022 was 2.7%, the Standard Deviation of that average is 9.4%. This means that for about 68% of the years, the Company's annual change in Active Healthcare costs could range from negative 6.7% to a positive 9.1%. This extreme level of volatility renders historical changes in Active Healthcare costs to be virtually worthless in determining future Active Healthcare costs.

Given the unreliability of the Company's actual annual change in Active Healthcare costs, it is prudent to project future increases in Active Healthcare costs based on the adjusted WTW medical trend rates, which have a proven record of accuracy, rather than the Company's historical experience.

OTHER EMPLOYEE BENEFITS COSTS

Q55. What are Other Benefits Costs?

A55. The costs of the Company's Other Employee Benefits are also reflected on Exhibit A-13, Schedule C5.11 (lines 13 through 25). These costs include a variety of other benefits including Accrued Vacation, Executive and Supplemental Retirement Plans, Supplemental Severance Plan, Supplemental Savings Plan (SSP), Deferred Compensation, Wellness Program, Life Insurance, Long-Term Disability, associated with the Affordable Care Act (ACA), General Benefits, Benefit Plan Administration Fees and Retirement Administration Fees. In total, these expenses are projected to increase from $5.318 million in the historic test year to $18.554 million in the projected test year, as shown on line 26 of Exhibit A-13, Schedule C5.11. As described in detail below and as reflected on page 2 of Exhibit A-13, Schedule C5.11, column (c), $11.170 million of this increase relates adjustments to normalize the Other Benefits expense reported in 2022 and $2.067 million relates to projected increases, as reflected on column (i).

Q56. What adjustments are you proposing to Accrued Vacation expense?

A56. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 13, I am proposing two adjustments to Accrued Vacation expense. The first, which is reflected on column (c), represents a normalization of the Company's recorded 2022 accrued

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Vacation expense and the second, which is reflected in column (i), represents the projection of this expense through the end of the projected test year.

Q57. What is the Normalization of the Company's Accrued Vacation expense?

A57. Accrued Vacation expense can vary from year to year based on the timing of the vacation earned and usage of vacation time by employees, as well as forfeitures. This volatility in annual accrued vacation expense has been traditionally addressed using a five-year average of the annual expense. Accordingly, the adjustment to Vacation Accrual expense reflected on page 2 of Exhibit A-13, Schedule C5.11, line 13, column (c), is based on the average of the recorded expense for the years 2018 through 2022 of negative $0.497 million. This results in an increase to Accrued Vacation expense of $4.942 million.

Q58. What is the basis for your projection of the Company's Accrued Vacation expense?

A58. The adjusted five-year average is escalated by the projected 3.0% labor annual cost increases through the end of the projected test year.

Q59. What is the basis for the Supplemental Severance Plan cost projections?

A59. The Supplemental Severance Plan, which was implemented on July 1, 2016, is designed to address the differences in full benefit eligibility retirement ages between the DTE Traditional Pension Plan and the MCN Energy Group, Inc (MCN) Traditional Pension Plan. As a severance plan, in accordance with the regulations of the U.S. Department of Labor, it is not subject to participation, vesting and funding requirements of ERISA. Eligible employees will receive a lump sum payment equal to the present value of the difference between the DTE Pension Plan and the MCN Pension at the termination of employment. Aon developed the projected cost of this plan, which is estimated to decrease from $0.734 million in 2022 to $0.110 million for the projected test year, as reflected on Exhibit A-13, Schedule C5.11, line 14.

Q60. What is the Supplemental Savings Plan?

A60. The SSP is a non-qualified benefit plan that does not meet the requirements under the Internal Revenue Code to be eligible for certain tax advantages, such as the deductibility by the Company of any contributions. Each year, the Internal Revenue Service (IRS) establishes limitations on employee annual eligible compensation and annual contributions to tax advantaged plans. To the extent an employee's annual eligible compensation or annual contributions, including the Company's match, to the Company's qualified plan exceeds the IRS limitations, employees that are Director level and above are eligible to participate in the SSP. By participating in the SSP, employees accrue benefits that are identical to the benefits available under the qualified savings plan. As such, the SSP is a "make-whole" benefit plan that merely puts the participating employees in the same place they would be in the absence of the IRS limitations.

Q61. What adjustments are you proposing to the SSP expense?

A61. I am proposing two adjustments to SSP expense. The first relates to a normalization of the actual 2022 SSP expense and the second relates to a projection of the SSP expense through the end of the projected test year.

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Q62. What is the normalization adjustment for 2022 SSP expense?

A62. Since the Company does not separately fund the Company's matches to the employees' contributions, the earnings and losses from the employees' directed investments is a cost incurred by the Company. The SSP normalization adjustment reflects an annual return on the investments of 6.80% in 2022, which is based on the ERoA used in the determination of the Company's pension costs in the historical test year. This results in a normalized SSP expense of $2.456 million compared to a negative expense of $3.599 million recorded in 2022, which represents an increase in SSP expense of $6.055 million, as reflected on page 2 of Exhibit A-13, Schedule C5.11, line 15, column (c). The increase in SSP expense reflects the difference between the negative return on the investments in the SSP and the ERoA of 6.80%.

Q63. What is the basis for projected the SSP expense for the projected test year?

A63. The increase in the normalized 2022 SSP expense of $2.456 million to $3.207 million for the projected test year, as shown on Exhibit A-13, Schedule C5.11, line 15, reflects an increase in the Company's matching contributions based on projected salary escalations and an increase in the expected earnings on designated investments. The SSP projection reflects an annual return on the investments of 7.60% in 2023, 7.90% in 2024 and 7.80% in 2025, consistent with the ERoA used in the determination of the Company's pension costs in the projected test year.

Q64. What adjustments are you proposing to Deferred Compensation Plan expense?

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A64. I am proposing two adjustments to Deferred Compensation expense. The first relates to a normalization of the actual 2022 Deferred Compensation expense and the second relates to a projection of the Deferred Compensation expense through the end of the projected test year.

Q65. What is the normalization adjustment for 2022 Deferred Compensation expense?

A65. Similar to the SSP, the Company's recorded costs are based on the return on the investment directives of the participating employees since the deferrals are not funded by the Company. The Deferred Compensation normalization adjustment reflects an annual return on the investments of 6.80% in 2022, which is based on the ERoA used in the determination of the Company's pension costs in the historical test year. This results in a normalized Deferred Compensation expense of $88,000 compared to a negative expense of $85,00 recorded in 2022, which represents an increase in Deferred Compensation expense of $173,000, as reflected on page 2 of Exhibit A-13, Schedule C5.11, line 16, column (c). The increase in Deferred Compensation expense reflects the difference between the actual negative return on the investments in the Deferred Compensation balances in 2022 and the Pension ERoA of 6.80%.

Q66. What is the basis for the projected Deferred Compensation Plan expense?

A66. The increase in the normalized 2022 Deferred Compensation Plan expense of $88,000 to $95,000 for the projected test year, as shown on Exhibit A-13, Schedule C5.11, page 2, line 16, column (j), reflects an increase in the expected earnings on designated investments. The Deferred Compensation Plan projection reflects an annual return on the investments of 7.60% in 2023, 7.90% in 2024 and 7.80% in 2025, consistent with the ERoA used in the determination of the Company's pension costs in the projected test year.

Q67. How did you project the increase in the Company's Wellness Program expense?

A67. As referenced in my discussion of Active Healthcare expense, the Company has a Wellness Program designed to produce significant reductions in future active healthcare expense. Wellness Program expense is projected to increase from $4.995 million in the historical test year to $5.560 million in the projected test year based on the adjusted healthcare trend annual escalations of 5.10% in 2023, 5.00% in 2024, and 4.00% in 2025 (Exhibit A-13, Schedule C5.11, line 17).

Q68. How did you project the Company's Life Insurance Expense?

A68. The Company's Life Insurance expense relates to life insurance provided to employees that provides coverage that is generally equal to the employees base annual salary. Because the coverage is based on employee salaries, I have adjusted the 2022 expense of $252,000 by the annual wage escalation of 3.0%, which produces a Life Insurance expense in the projected test year of $276,000, as reflected on line 18 of Exhibit A-13, Schedule C5.11.

Q69. How have you projected the Company's Long-Term Disability Expense?

A69. Actual 2022 Long-Term Disability Expense is projected to increase from $1.354 million to $1.480 million during the projected test year based on the assumption that disability claims costs are primarily driven by labor costs escalations, which are assumed to be 3.0% per year between 2022 and the end of the projected test year, as reflected on line 19.

Q70. How did you develop the projections for the other items included in Other Benefits on Exhibit A-13, Schedule C5.11?

A70. On lines 20 through 25 of Exhibit A-13, Schedule C5.11 are the components of the other items included in the Company's Other Benefits. The 2022 ACA expense of $19,000 on line 20 reflects the actual expense recognized for the Comparative Effectiveness Research Fee, which is escalated at the annual Active Healthcare inflation rates, resulting in $22,000 of ACA expense for the projected test year. General Benefits Expense is reflected on line 21 and is projected based on the actual amounts recorded in 2022 of $2.198 million and escalated at the overall rate of inflation as measured by the Consumer Price Index through the end of the projected test year, which results in projected General Benefits Expense of $2.395 million. Benefit Plan Administration Fees (line 22) and Retirement Administration Fees (line 23) in 2022 of $6.697 million and $325,000, respectively, are projected to increase to $7.296 million and $354,000, respectively based on the projected overall inflation rate assumptions. Also included in Other Benefits, Exhibit A-13 Schedule C5.11 are Medical Refund Amortization (line 24) and O&M Project reimbursements (line 25), which are both sponsored by Witness Uzenski.

Q71. What are the Company's total projected employee pensions and benefits expenses for the projected test year?

A71. The total projected employee pensions and benefits expenses of $103.590 million is reflected on Exhibit A-13, Schedule C5.11, line 27. After adjustments for the

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impact of the portion of these costs to be capitalized and transferred, as well as the elimination of costs allocated to the Company's separate surcharge programs, as sponsored by Witness Uzenski, employee pensions and benefits expenses for the projected test year are reduced to $84.259 million, as reflected on Exhibit A-13, Schedule C5.11, line 31.

LABOR COST ESCALATION

Q72. What annual labor cost escalation assumptions are appropriate for the projected test period?

A72. Annual labor cost escalation assumptions are required for both the Company's represented and non-represented employees. Based on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by at least 3% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions.

Non-represented employee compensation is generally adjusted annually based on a review of pay practices of other employers, changes in the external competitive market and internal pay equity. Consistent with this practice, all non-represented non-management employees received an overall pay increase of 3% in 2023. This 3% pay adjustment was comparable to the annual pay adjustments in every year since 2010. In addition to the annual pay adjustment program, employees generally receive pay increases based on promotions.

Based on the above, I have determined that annual escalations of 3.0% for 2023, 2024, and 2025 are a conservative estimate of the Company's expected increase in its labor rates.

EMPLOYEE COMPENSATION

Q73. What is the Company's compensation philosophy and framework for non-represented employees other than Executives?

A73. Non-represented employees are those employees not covered by any Collective Bargaining Agreements with the Company's union organizations. Compensation for employees covered by Collective Bargaining Agreements is established pursuant to negotiations. Non-executive employees are generally defined as those with titles below Vice President level. DTE Electric's compensation philosophy is to provide pay programs that: 1) attract, retain, and motivate employees; 2) ensure that pay is externally competitive (i.e., paid near market median); and 3) differentiate total rewards based on both organizational unit results and individual contributions.

At DTE Electric, total annual compensation for all non-represented employees has two primary components: base pay and variable pay, as delivered through the Company's incentive compensation programs. Employee base pay is reviewed annually and adjusted (if appropriate) based on the position relative to what the external market pays for similar positions and individual performance. Variable pay is based on the achievement of Company, as well as departmental and individual results. Variable pay is made up of both short-term incentive and long-term incentive plans.

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Q74. How does the Company's philosophy regarding incentive compensation compare with that of its peers?

A74. Incentive compensation programs are a component of total compensation practices for the vast majority of energy companies for their non-represented employee population, as described below. Base pay is set lower than it otherwise would be because of the variable pay component. When considered holistically, the Company's base and variable pay plans provide a framework of market-based total annual compensation pay opportunities for non-represented employees. It is the total annual cash compensation, as represented by these two components, that prospective and current employees use to gauge whether DTE Electric's compensation is competitive with other potential employers.

Q75. How does the Company's non-represented compensation philosophy and framework benefit customers?

A75. DTE Electric's compensation philosophy and framework provides a benefit to customers by attracting and retaining employees with the requisite skills and experience to ensure safe, reliable, and high-quality customer service delivery, and by recognizing and rewarding effective and efficient performance. A competitive compensation policy also serves to effectively retain employees, minimizing the risks and costs of high employee attrition. This philosophy directly benefits all customers by providing a high level of service at a competitive cost and provides incentives to focus future job performance on those activities that provide the most benefit to customers.

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Q76. What is the external comparative market used by the Company to determine the external market for compensation?

A76. The external comparative market for positions varies based on the specific job. Some jobs are compared to those in utilities of similar size (e.g., revenue, number of employees, etc.), other jobs are compared to general industry located in Southeastern Michigan, and yet other jobs to general industry located within the United States. The relevant market will depend upon the requisite skills and abilities required of the job and the nature of the recruitment source. For example, the comparative market for an administrative assistant is the general industry within Southeastern Michigan while the comparative market for a manager of nuclear operations is utilities within the Midwestern United States (primarily), or within the entire United States (secondarily).

Q77. How is benchmark data obtained from the external comparative market?

A77. The Company participates in and/or purchases published salary surveys from several different organizations. The surveys typically report median base salary, target incentives, and median total cash compensation by job classification.

Q78. How are base salaries determined?

A78. Base salaries are targeted around the median base salary levels of the competitive market as adjusted for differences in company size and scope where appropriate. All non-executive positions are placed in a salary zone based on external benchmarking. The mid-point of the salary zone is based on the market median for comparable work in comparable companies. A range is provided above and below the midpoint to allow for differentiation based on applicable skills and experience, as well as demonstrated performance. The ranges are reviewed periodically to help ensure they remain competitive in the external market.

Q79. Does the Company benchmark the variable component of compensation?

A79. Yes. The Company reviews several surveys that provide information on a number of variable pay indices. In addition, the surveys report data for employee groupings such as exempt employees, non-exempt employees, managers, and executives.

Q80. Could an alternate compensation system be structured, eliminating variable components?

A80. Yes. The Company could raise employees' base pay to the market levels for total compensation in lieu of providing variable pay opportunities to maintain a competitive total compensation level. However, this would have several undesirable effects. For example, raising employees' base pay to the total compensation market levels would result in a higher level of fixed costs tied to base salaries, such as certain defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits. Moreover, given the well-recognized motivational value of variable pay compensation programs, as described below, delivering employee compensation solely in fixed salary would diminish the performance incentive for employees to provide superior service to customers. Annual incentives ensure that individuals have an element of "at risk" compensation that allows the Company to differentiate pay based on performance and allocate compensation to those employees that are most deserving.

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EXECUTIVE COMPENSATION

Q81. How does the compensation program for executives differ from that for non-executives?

A81. The compensation program for executives differs in three respects. First, the comparative market for compensation benchmarking is defined as a specific group of peer companies from which data are obtained through a custom study generally performed every two years. Second, a higher proportion of executives' compensation is delivered in the form of variable pay. The third way in which the executive compensation program differs is with respect to governance. The compensation programs for Company executives must be approved by the Organization and Compensation Committee of the DTE Energy Board of Directors.

Q82. What is the comparative market for executive compensation?

A82. The comparative market used by DTE Energy for determining the alignment of its executive compensation programs with similar companies consists primarily of utilities (including utility holding companies) and broad-based energy companies selected on the basis of revenues, financial performance, geographic location, and availability of compensation information.

Q83. What are the key components of the Executive Compensation Program?

A83. The key elements of the Executive Compensation Program are base salary and variable pay (annual incentive plan and long-term incentive awards).

Q84. How are base salaries determined?

A84. Base salaries are targeted around the median of the comparative market. Appropriate methods of measurement are used to consider differences in company size and scope. In addition, midpoints are established for those executives whose jobs cannot be easily matched in the comparative market. These midpoints are designed to allow adequate differentiation for 1) individual potential, 2) contributions made, and 3) the length of time the executive has been in his or her position.

COMPETITIVE COMPENSATION ANALYSIS

Q85. Has the Company prepared an analysis of its compensation practices relative to the market medians?

A85. Yes. DTE Electric has performed an analysis of virtually all incumbent salaries as of December 31, 2022, showing that DTE's compensation practices are competitive with market medians. Exhibit A-21, Schedule K1 reflects a summary of the market median for all DTE Electric positions for which corresponding positions have been identified, other than those employees covered by collective bargaining agreements. In addition, Exhibit A-21, Schedule K1 reflects those positions at DTE LLC that primarily support DTE Electric. Exhibit A-21, Schedule K1 reflects employee compensation information organized based on Career Family classifications used by DTE Electric. A Career Family is a grouping of jobs based on similar skill requirements and job content in a specialized discipline (i.e., Finance, Engineering, Information Technology, etc.) that may or may not fit into a business unit organizational structure. For example, Engineering or Finance Career Families could exist in several organizational units.

Q86. How is an analysis of a competitive pay structure performed?

A86. An analysis of market-based pay structure is performed by identifying comparable positions and determining the compensation ranges paid by similar employers in relevant locations. A more expansive description of the means of assessing a competitive pay structure is provided in an article published by Salary.com, entitled The Basics of Market Pricing a Job (January 26, 2017).

Q87. Is the Company's use of a market pricing approach to employee compensation consistent with others?

A87. Yes. According to a recent survey performed by WorldatWork and Deloitte Consulting, entitled 2019 Survey of Salary Structure Policies and Practices, more than half of the companies surveyed use a market pricing model for setting compensation levels.

Q88. Why are employees covered by collective bargaining agreements excluded from this analysis?

A88. Compensation levels for unionized employees are determined through a negotiated process, which involves a variety of work rules and benefit related issues, rather than determined strictly through market analysis. Moreover, the specialized skills and experience required by many of the positions are not readily comparable to other positions in the local market. Thus, a comparison of pay levels for those employees covered by collective bargaining agreements is not useful in this context.

Q89. What conclusions can be drawn from Exhibit A-21, Schedule K1?

A89. In summary, Exhibit A-21, Schedule K1 demonstrates that the weighted average of the annual base compensation for all positions with incumbents as of December 31, 2022, with available position matches was a mere 0.1% higher than the average of median market base compensation. Plus, this analysis further demonstrates that total cash compensation for all positions with incumbents as of December 31, 2022, with available position matches was 0.4% less than the average of median market for total cash compensation. This analysis concludes that the Company's total compensation is insignificantly different from the market medians and confirms that the Company's compensation practices are consistent with the Company's compensation policy to pay employees near the market median for comparable positions on a total cash compensation basis. Moreover, a comparison of the Company's base salaries, which excludes short-term incentive compensation, to the market medians for total cash compensation, which is inclusive of short-term incentive compensation, shows that in the absence of the Company's short-term incentive compensation programs, the Company's pay would be 10.7% less than the market medians.

Q90. What is included in the total cash compensation amounts?

A90. Total cash compensation reflects base pay as of December 31, 2022, and the Target payout levels for those employees eligible to participate in the Company's short-term incentive compensation programs. Although the analysis on Exhibit A-21, Schedule K1 does not reflect the value of the Company's Long-Term Incentive Plan, as it is primarily for executive level positions, a separate analysis of executive compensation prepared by Aon, which is inclusive of long-term plans, shows that total compensation is about 9% less than the median of the Company's peer group, as discussed in more detail below.

Q91. How was the market median for the positions determined?

A91. As described above, the Company subscribes to several compensation survey providers that create comprehensive databases of job descriptions that enables the Company to match the job requirements, including education, expertise and experience of existing positions with market surveys. After matching job positions are identified, actual base and total compensation ranges are developed from the salary survey database. The information on Exhibit A-21, Schedule K1 was derived from the Company's compilation of the compensation for positions with an incumbent as of December 31, 2022.

Q92. What proportion of DTE Electric's total employee population as of December 31, 2022, is reflected in this analysis?

A92. As of December 31, 2022, practically all (99.5%) of the employee population at DTE Electric, as well as DTE LLC employees that provide supporting services to DTE Electric. This is exclusive of those employees represented by collective bargaining agreements.

INCENTIVE COMPENSATION

Q93. What are you proposing regarding the level of incentive compensation expense to be included in the Company's revenue requirement?

A93. I am proposing that the projected incentive compensation expense of $59.504 million related to the Company's short-term and long-term incentive compensation plans be included in the revenue requirement adopted by the Commission in this proceeding, as described in more detail below. The components of the projected $59.504 million of incentive compensation expense are detailed in Table 3 reflected in response to Q120.

Q94. Is the Company requesting recovery in rates for all incentive compensation expenses?

A94. No. While the Company's compensation expenses are reasonable, $10.157 million of incentive compensation expense related to DTE Energy's Top Five Executive Officers has been excluded. This exclusion is reflected on Exhibit A-3, Schedule C19 as supported by Witness Uzenski and has been excluded from Table 3 reflected in the response to Q120.

Q95. What is the basis for your proposed inclusion of $59.504 million of incentive compensation expense in the Company's revenue requirement?

A95. In summary, my proposal to include all the Company's projected incentive compensation expense, exclusive of the portion related to the Top Five Executive Officers, is based on the prevalence of incentive compensation programs and the resultant need for the Company to have total compensation programs that enable it to be competitive with other employers. As described above, the Company's existing total cash compensation is in line with the market, as is the total compensation for its executives. Moreover, in the absence of the incentive compensation programs, total cash compensation for the Company's employees would be unreasonable as it would total 10.7% less than the market medians, as reflected on Exhibit A-21, Schedule K1, and total compensation for its executives

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would be 70% less than market, as reflected in Table 2 below in Q100. The remainder of my testimony will demonstrate that the Company's incentive compensation programs are both reasonable and prudent and, therefore, a necessary cost of the Company doing business that should be reflected in the Company's revenue requirements.

Q96. Are there any employee motivational advantages to including an incentive-based compensation component in a company's overall compensation design?

A96. Yes. The underlying principle of incentive compensation plans is to motivate improved organizational performance. An effective incentive compensation plan provides a "pay-for-performance" environment intended to motivate individual and team achievement of measurable goals.

Q97. Is there any evidence that incentive-based compensation is effective in motivating improved organizational performance?

A97. Yes. A comprehensive analysis of the impact of incentive compensation plans on organizational performance concluded that programs that provide tangible incentives for achievement of certain goals lead to a 27% increase in organizational performance (Incentives, Motivation and Workplace Performance: Research & Best Practices, The International Society for Performance Improvement, Spring, 2002). This study observes that the source for such organizational performance improvements is that employees 1) value their work tasks more, 2) have more self-confidence and esteem for their employers, 3) are more persistent at work tasks, and 4) strive for high levels of accomplishments. Moreover, this study notes that long-term incentive plans provide even greater

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performance improvements. In addition, an Aon study of Variable Compensation Measurement Survey issued in 2018 reported that 86% of participants in the survey indicated that their variable compensation plans resulted in improved business results.

Q98. Are incentive compensation programs a typical element in compensation at other companies?

A98. Yes. According to a 2021 study issued by WorldatWork and Compensation Advisory Partners, most companies had short-term and long-term incentive programs. This indicates that incentive compensation programs are a prevalent practice among most companies. (Incentive Pay Practices, Publicly Traded Companies, WorldatWork and Compensation Advisory Partners). Moreover, a 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers utilized broad-based incentive compensation programs.

Q99. Do the Company's incentive compensation plans result in unreasonable compensation?

A99. No. As explained above, the Company benchmarks its total compensation for non-represented employees against relevant peers, inclusive of incentive compensation, and establishes a mid-point salary range based on the median market level. Moreover, based on a recent survey by Aon, the total compensation of DTE Energy's Executives is about 9% less than the median of its peers based on Target level performance, inclusive of the long-term incentive compensation. The Company's incentive compensation programs are merely a component of the total compensation policies required for the Company to be competitive with its peers,

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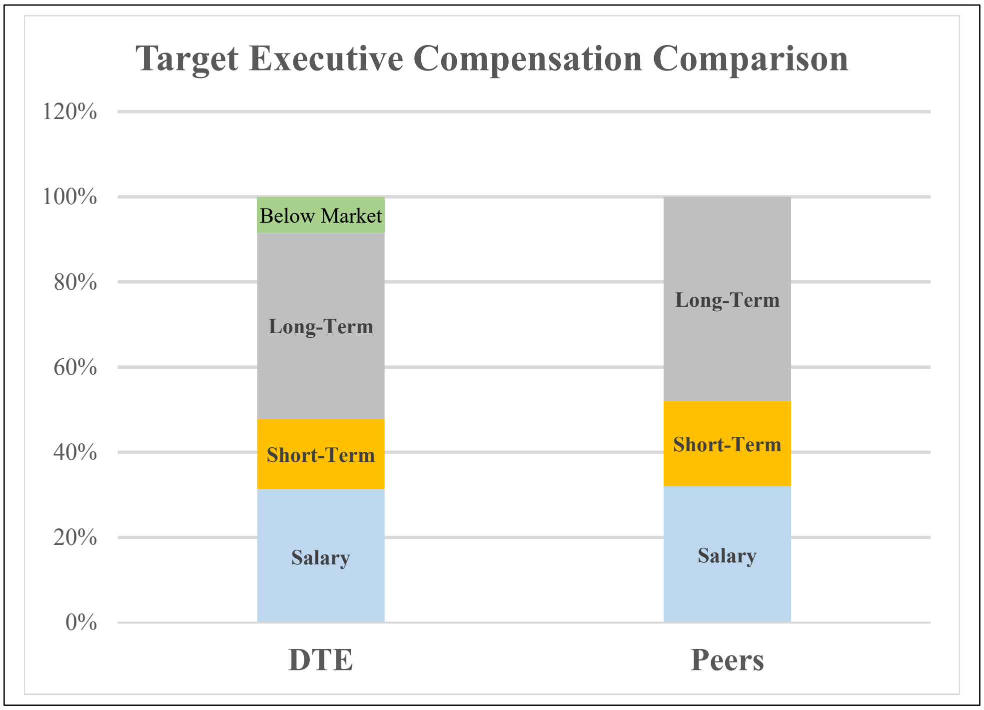
rather than a supplement. Indeed, in the absence of the incentive compensation programs, total compensation for the Company's non-represented population would be more than 10% below market, as reflected on Exhibit A-21, Schedule K1. Additionally, as indicated in Table 2 in the response to Q100 below, DTE Energy's Executives would be substantially less than its peers, since about 70% of total compensation is delivered through short and long-term incentive compensation programs, by both DTE and its peers.

Q100. How do the components of the Company's total Executive compensation practices compare to the Company's peers?

A100. Based on the Aon survey referenced above, a comparison of the relative magnitude of the Company's salary, short-term and long-term pay components for Executives to the 50th percentile of its peers is reflected in Table 2.

Table 2



Q101. What are the specific components of the Company's incentive compensation programs?

A101. The Company has in place incentive compensation plans for both its Executive and all other non-represented employees. Short-term incentive plans are provided through the Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP). Additionally, a multiple year incentive plan, which is available to all managers and above and up to 10% of other eligible non-represented employees, is delivered through Performance Shares granted pursuant to the Long-Term Incentive Plan (LTIP).

Q102. What is the AIP?

A102. The AIP is a short-term variable pay program available to senior management level employees to motivate performance. The 2023 AIP measures and relative weights for DTE Electric (other than Nuclear Generation), Nuclear Generation, and DTE Energy Corporate Services LLC are reflected on Exhibit A-21, Schedules K2, K3 and K4, respectively. For each measure, a Target is established for which a 100% payout will be earned. Performance less than Target, but above a minimum Threshold, results in a payout between 25% of Target and 100%, a payout of 100% of Target when performance is at Target, and performance between Target and the Maximum level results in a payout of up to 175% of Target for non-executive participants of the AIP and up to 200% of Target for Executive participants of the AIP.

Q103. Which employee classifications are eligible to participate in the AIP?

A103. All Executive level employees, generally those with titles of Vice President and above, and Directors participate in the AIP. All other non-represented employees are eligible to participate in the REP.

Q104. What are the components of the REP?

A104. The REP is identical to the AIP except that Threshold performance is at 50% of Target and the Maximum performance payout is 150% of Target. The 2023 REP measures and weightings are reflected on Exhibit A-21, Schedules K2 through K4. The REP measures are identical to the AIP measures other than the REP excludes the Gallup survey of employee engagement measure in recognition that the Company's leadership is responsible for providing an environment of high employee engagement.

Q105. What are the categories of measures included in the AIP and REP?

A105. There are four categories of measures in both the AIP and REP. Specifically, Financial Performance, Customer Satisfaction, Safety and Engagement, and Operating Excellence.

Q106. What are the financial measures included in the AIP?

A106. There are three financial measures for DTE Electric employees that are designed to create a clear line of sight for all employees to focus on operating excellence by rewarding employees when the Company is successful.

1) DTE Electric Operating Earnings objective is based on the Company realizing the Commission authorized return on equity.
2) DTE Electric's Cash from Operations is similarly based on the authorized return on equity but is adjusted for non-cash items. The inclusion of a cash flow measure recognizes the importance of DTE Electric maintaining a high credit rating to allow continued access to the capital markets at reasonable costs and terms to ensure sufficient capital investment to continue to serve our customers.
3) DTE Energy's Earnings per Share measure is based on the midpoint of 2023 earnings guidance.

Nuclear Generation Financial Performance measures consist of DTE Electric Operating Earnings and Nuclear Generation Operation and Maintenance Expense. The Financial Performance measures for DTE LLC reflect DTE Energy's Operating Earnings per Share and Cash from Operations.

Q107. What are the Customer Satisfaction measures?

A107. There are two customer satisfaction measures that are intended to focus employees on improving the experience that our customers have in their interactions with the Company. The measures are:

1) The Net Promoter Score is a measure of the extent to which customers are likely to recommend the Company to their friends and colleagues. The Target in 2023 is 39, which is the same as the actual NPS in 2022. However, macroeconomic factors in 2022 and 2023, including 40-year high inflation and historically low consumer confidence, as noted by the University of Michigan Consumer Confidence Surveys results, among other factors, have resulted in reduced NPS scores nationwide by virtually all industries. Therefore, considering these conditions, maintaining a NPS score of 39 in 2023 is estimated to represent an effective 4 point increase.

2) The MPSC Customer Complaints measure represents the number of formal complaints made to the MPSC regarding both DTE Gas and DTE Electric as reported to the Company by the MPSC. The MPSC Customer Complaints Target for 2023 is 1,912.

Q108. What are the measures related to Safety and Engagement?

A108. There are three measures related to safety and engagement. One measure pertains to employee engagement as measured by the Gallup survey, as well as two employee safety related measures, as described below.

Q109. What is the measure related to Employee Engagement?

A109. The Gallup measure of Employee Engagement is reflective of the direct correlation between the level of active employee engagement and the performance of an organization. The 2023 Target of 4.26 is based on a grand mean of the results of the Gallup surveys of employees and represents top decile performance relative to Gallup's overall database. Employee Engagement is a statistically significant measure of the level of commitment employees have to an organization's success and is not merely a measure of employee satisfaction.

Q110. What are the Safety related measures?

A110. DTE Electric has two safety-related measures.

1) The first is the OSHA Recordable Incident Rate (RIR), which measures the recordable injuries per 100 employees divided by the actual number of hours worked, as defined by the Occupational Safety and Health Administration (OSHA). This is a standard measure of safety performance used nationwide. The measure is intended to create a heightened focus on the importance of safety in the workplace. The RIR Target for 2023 is .57, which is near the very top performance in the industry.
2) The second is High Energy Serious Injury or Fatality (HSIF), which is a measure adopted by the Edison Electric Institute that recognizes the degree of seriousness of an injury in the context of a dangerous event. The 2023 Target of zero is based on an improvement from the five-year average of 4.

Q111. What are the Operating Excellence measures for 2023?

A111. DTE Electric has four Operating Excellence measures that reflect specific operating priorities for 2023 to motivate the achievement of certain operating objectives important to the Company, its customers, and the Commission. Two of these measures relate to Distribution System Reliability and the other two relate to Generation Reliability.

The two Electric Distribution Reliability Measures are:

1) The System Average Interruption Duration Index (SAIDI) exclusive of Major Event Days (MEDs). The 2023 Target is 150 minutes.
2) The percentage of customers that experience four interruptions or more (CEMI4) in a calendar year. The Target in 2023 is 7.55%.

The two Generation Reliability Measures are:

1) The percentage of hours that DTE Electric's coal, gas, and renewable plants are mechanically available to produce power. The 2023 Target is 81.8%.
2) Nuclear On-Line Reliability Loss Factor (ORLF), which is energy generation losses corrected for refueling outage losses and exempt activities. The 2023 ORLF Target is 1.03%.

Q112. What are the operating measures applicable to the Nuclear Generation business unit?

A112. Nuclear Generation has four Safety and Engagement related measures and four Operating Excellence measures, discussed below in further detail.

Q113. What are Nuclear Generation's Safety and Engagement related measures?

A113. In addition to Employee Engagement, as measured by Gallup surveys, and the OSHA Recordable Incident Rate, as described above, Nuclear Generation also has two additional safety measures.

1) The first is the annual Total Industrial Safety Accident Events (TISA Events), which is a nuclear industry measure that is aligned with the Institute of Nuclear Power Operations (INPO). The Target is zero incidents in any calendar year quarter.
2) The second relates to On-Line Radiation Exposure, which is designed to maintain a focus on the safety of personnel. The 2023 Target is 50.6 Rem, which is a standard unit of measure of exposure to radiation.

Q114. What are the Operating Excellence measures related to Nuclear Generation?

A114. Nuclear Generation has four Operating Excellence measures.

1) The first relates to On-Line Reliability Loss Factor, as described above.
2) The second measure regarding Operational focus pertains to a group of 11 measures that relate to Fermi 2 plant performance. The 2023 Target is 93.4.
3) The third measure is an index of Annualized Work Management, which consists of 10 individual indicators. The 2023 Target is 99.8.
4) The final Nuclear Generation measure relates to the Nuclear Refuel Outage Milestone, which is a measure of the effective planning and preparation for refueling planned in 2024. The Target for 2023 is that 30 milestones are achieved at 98% performance and four are achieved with performance between 96% and 98%.

Q115. Are there other AIPs and REPs that impact DTE Electric's expenses?

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No.

A115. Yes. In addition to the DTE Electric and Nuclear Generation measures described above, there are also AIPs and REPs in place for corporate staff employees at DTE LLC that provide services to all DTE Energy business units, including DTE Electric. The DTE LLC measures reflect certain DTE Electric and Nuclear Generation measures, as well as measures related to DTE Gas. The specific DTE LLC measures and weightings related to DTE Electric and Nuclear Generation are reflected on Exhibit A-21, Schedule K-4.

Q116. What is the Company's Long-Term Incentive Plan?

A116. The LTIP provides the opportunity for certain individuals to receive retention-oriented or performance-based rewards delivered via shares of DTE Energy common stock, either Performance Shares, which are based on the achievement of multi-year performance objectives, or through Restricted Stock. Currently, 70% of the value of awards for executives and directors is through grants of Performance Shares and 30% of the value of awards is through Restricted Stock, while 100% of the awards to other eligible employees are through Performance Shares. The objective in granting shares through this program is to both motivate superior results as well as provide a means to retain key employees and is consistent with the practices of most companies, as reflected in the WorldatWork and Compensation Advisory Partners survey, referenced in Q98 above.

Q117. What are the performance share measures used in the 2023 LTIP?

A117. The measures are shown on Exhibit A-21, Schedule K5.

Q118. What is the rationale for the use of these measures?

Line No.

A118. These measures generally reflect the long-term financial performance of DTE Energy and are intended to motivate employees of the individual operating companies, such as DTE Electric, to keep in mind the role of their own contributions to the overall long-term success of DTE. Accordingly, the predominate measure for DTE Electric and DTE LLC (80% for both) is the total return to DTE Energy shareholders (i.e., capital appreciation and dividends) relative to a group of peer companies over the next three years. The second financial measure included in the LTIP, which contributes 20% to the total weighting, is DTE Energy's three-year cumulative Operating Earnings per Share. The three-year focus of the performance-based measures is designed to motivate decisions and actions that produce sustainable benefits rather than short-term actions that may entail long-term risks.

Q119. What is the basis for the costs of the LTIP?

A119. The LTIP costs incurred in 2022 pertain to the grants of Performance Shares and Restricted Stock. The expense related to the Restricted Stock is not conditioned on any Company performance measures but rather is exclusively based on the number of shares granted at the date of grant. In contrast, Performance Shares expense is based on the achievement of the predetermined performance objectives. The recognized cost of Performance Shares is based on the number of shares granted at the market price of DTE Energy's common stock at the date of grant but with adjustment in the number of shares based on actual performance. The Performance Shares expense included in Table 3 is based on Target performance.

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Q120. What is the incentive compensation expense if the Company achieves all of its Financial and Operating Targets?

A120. The net expense to DTE Electric in the projected test period of the Company achieving all its Targets for the incentive compensation plans, exclusive of the expense related to the Top Five Executive Officers, is $59.504 million. The table below summarizes the expense for the projected test period by the nature of the plans, the classification of the employees eligible and the basis of the metrics used.

Table 3

	LTIP	AIP	REP	Total
		(000's Omitted)		
Financial				
DTE Electric	$5,858	$615	$7,029	$13,502
Nuclear Gen	1,395	92	839	2,326
DTE LLC	13,154	3,509	6,741	23,404
	20,408	4,215	14,609	39,232
Operating				
DTE Electric	0	504	5,758	6,262
Nuclear Gen	0	200	2,527	2,727
DTE LLC	0	3,862	7,420	11,281
	0	4,566	15,705	20,271
Total				
DTE Electric	5,858	1,119	12,787	19,764
Nuclear Gen	1,395	292	3,367	5,054
DTE LLC	13,154	7,370	14,161	34,686
	$20,408	$8,781	$30,315	$59,504

Q121. Why are the expenses for DTE LLC most of the incentive compensation expenses?

A121. DTE LLC provides a variety of administrative and other services that are common to both DTE Electric and DTE Gas for which the costs are billed to the operating companies, as explained by Witness Uzenski. In addition, DTE LLC employs all the Executives of DTE Energy, including the Officers of DTE Electric.

Q122. How have you reflected the Operating Excellence measures related to DTE Gas in the AIP and REP for DTE LLC?

A122. While the AIP and REP expenses allocated to DTE Electric in the historic period from DTE LLC include some measures related to DTE Gas, the AIP and REP weightings for DTE LLC have been adjusted to exclude the measures specifically related to DTE Gas.

Q123. Are all incentive compensation costs dependent on the Company's financial or operating performance?

A123. No. As described earlier, a portion of the DTE Energy shares granted under the LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the expense of Restricted Stock is not variable based on either the Company's financial or operating performance. The only contingency is that the employee forfeits the Restricted Stock if they leave the Company, other than through retirement or the event of the employee's death or disability.

Q124. How does the lack of variability in the LTIP expense affect its treatment in your analysis of incentive compensation?

A124. Although Restricted Stock grants are made under the LTIP, the ultimate payouts are not dependent on future Company or employee performance, and therefore, Restricted Stock is not regarded as an element of the Company's incentive

Line No.

compensation expense. Accordingly, the projected test year Restricted Stock expense of $8.960 million has been excluded from Table 3 above.

Q125. Has the Commission provided any criteria for the inclusion of incentive compensation expense in the Company's revenue requirements?

A125. Yes. The Commission has indicated in all its recent Orders addressing incentive compensation programs that inclusion of incentive compensation expense in a company's revenue requirement was dependent on a showing that the incentive compensation programs provided benefits to customers in excess of the expense.

Q126. Has the Company performed an analysis of the customer benefits of the Company's incentive compensation plans?

A126. Yes. The Company has performed a comprehensive analysis of the customer benefits that would be derived from the achievement of the financial and operating metrics included in the Company's short and long-term incentive plans relative to their expense. This analysis, as reflected on Exhibit A-21, Schedule K6, demonstrates that the calculated aggregate benefit of $104.478 million exceeds the total incentive compensation expense of $59.504 million by $44.974 million.

Q127. How did you calculate the benefits of the Financial measures?

A127. While the Company has not quantified the benefits to customers of each of the financial measures, one measure that had specifically quantifiable benefits is the Cash Flow from Operations measure within the AIP and REP, as reflected on line 8 of Exhibit A-21, Schedule K6. This measure is focused on the Company maintaining its "A" debt rating from Standard & Poor's and comparable ratings by the other major debt rating firms. The yield spread between utility bonds for bonds with an "A" rating compared to "BBB" rated bonds is 23 basis points. Based on the long-term debt balances included in the capital structure sponsored by Company Witness Vangilder, a downgrade in the Company's credit rating would increase the Company's annual interest costs by $19.9 million.

Q128. How are the benefits of the Company achieving Target performance for the Operating measures reflected on Exhibit A-21, Schedule K6 determined?

A128. The benefits of the Operating measures are computed based either on the avoided costs to the Company, which results in lower future revenue requirements, or based on the value to customers of improved performance. The reference points to determine improvement are, in most instances, based on the Company's actual performance in the 2022 historical test year, but when 2022 results are not representative, either an historical average or a comparison to external peer groups is used. In those instances, in which the Company's Targets are based on superior performance relative to peers, then measures of peer performance are used. The benefits of achieving Target performance are allocated between the AIP and REP components based on the relative incentive compensation expense for each measure.

Q129. How did you quantify the benefit of achieving Target performance levels in the Customer Satisfaction measures?

A129. The benefits of achieving the 2023 Target of 39 Net Promoter Score (NPS) are based on the expectation that improvements in the NPS score will result in fewer customer calls. The 2023 Target of 39 is expected to produce $2.2 million of customer benefits based on avoided Company costs and customer costs.

The customer benefits of attaining Target performance for MPSC Customer Complaints measure is based on the avoided costs to both the Company and its customers due to the reduced time spent by employees and customers resolving complaints for a total savings of $29,000.

While the total quantified benefits related to the Customer Satisfaction measures are less than the related expense, there can be little doubt that an emphasis among the Company's employees on improving the experiences customers have with the Company results in additional significant non-quantifiable benefits to both customers and the Commission.

Q130. How did you determine the benefits of the Employee Engagement measure?

A130. The quantifiable benefits of a highly engaged workforce are based on three critical dimensions identified by Gallup: absenteeism, productivity, and safety incidents. According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1% reduction in absenteeism, a 1.8% increase in productivity, and a 3.8% reduction in safety incidents. Compared to the 80th percentile of Gallup survey results for all companies included in Gallup's database, the achievement of the 2023 Target Gallup Target will generate O&M savings of $11.9 million, which is attributed exclusively to the AIP because the Employee Engagement measure is not included in the REP.

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Q131. What are the expected benefits of the Company achieving Target level performance regarding the OSHA Recordable Incident Rate (RIR)?

A131. The benefits of achieving the OSHA Recordable Incident Rate (RIR), and the Nuclear Total Industrial Safety Accident Rate goal, are based on the estimated direct costs of non-fatal incidents of $50,000, as developed by OSHA, as adjusted for inflation through 2022, and a study by Liberty Mutual that estimates the indirect cost of an OSHA recordable incident is about 3.0 times the direct costs, resulting in an estimated total cost of $201,000 per incident, in current dollars. Based on Target level performance, relative to the Company's five-year average results in an estimated benefit of $2.6 million net of the savings capitalized. The benefits of achieving the OSHA RIR Target are allocated to all the other safety measures in proportion to the costs of each measure, as reflected on lines 29 through 35 of Exhibit A-21, Schedule K6.

While the quantified savings of the safety related metrics are less than the related costs, much like the customer service-related measures, the benefits of maintaining an organizational focus on the safe operation of the Company's system for the benefit of its employees, customers, and the communities where the Company operates are undoubtedly substantial.

Q132. How did you quantify the savings related to improvements in distribution system reliability?

A132. The benefit of achieving the SAIDI excluding MEDs Target is based on comparing the 2023 Target of 150 minutes to the five year average of SAIDI excluding MEDs of 161 minutes, which represents a reduction of 11 minutes. The derivation of the

Line No.

benefits to customers is based on the Interruptions Cost Estimation Calculator as developed by Nexant, Inc. and the Lawrence Berkeley National Lab. A reduction of eleven minutes in the SAIDI excluding MEDs produces an annual customer benefit of $43.1 million. The benefits of achieving Target performance in the SAIDI excluding MEDs measure have been allocated equally between the SAIDI exclusive of MEDs measures and CEMI4 Percent of Customers measure due to the close relationship of each of these measures to distribution system reliability, as reflected on lines 40 and 42 of Exhibit A-21, Schedule K6.

Q133. Have you quantified the benefits of the Generation Availability measure?

A133. The 2023 Generation Availability Target of 81.8% reflects a modest increase from the four-year average of actual Generation availability of 81.7%. Accordingly, I have not quantified the customer benefits of the increase in Generation Availability.

Q134. What are the benefits of an increase in the Nuclear On-Line Reliability Loss Factor?

A134. The benefits of an increase in the Nuclear Power Plant Reliability reflect an increase from the On-Line Reliability Loss Factor at Fermi 2 from the five-year average of 4.39% to the 2023 Target of 1.03%. The savings computed are based on the differential between Fermi 2's marginal fuel costs and the average market price of avoided energy purchases combined with value of increased capacity for a total annual savings of $24.7 million. These savings are allocated to the Nuclear related operating measures included in the AIP and REP in proportion to the costs of each measure. Specifically, $19.0 million is assigned to Nuclear On-Line Reliability

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Loss Factor measure and $1.9 million is assigned to each of the three other Nuclear related measures, as reflected on lines 46 through 52 of Exhibit A-21, Schedule K6.

Q135. Have you quantified any additional savings related to the other Nuclear Generation measures included in the AIP and REP?

A135. No. The Nuclear On-Line Reliability Loss Factor measure represents the only quantifiable benefits of the Company meeting its Target performance levels for Fermi 2. While there is indisputable value in the various specific measures within the other Nuclear measures, the benefits of Fermi 2 achieving its On-Line Reliability Loss Factor Target has been attributed to the other AIP and REP Nuclear Operating Excellence measures.

Q136. What is your conclusion regarding the cost effectiveness of the Company's incentive compensation plans?

A136. As reflected on Exhibit A-21, Schedule K6, it is clear the quantified customer benefits of the Company achieving Target performance levels are substantially greater than the related expense.

Because the Company's overall employee compensation approximates the market, inclusive of incentive compensation and the quantified benefits exceed the projected incentive compensation expense, the Company's total incentive compensation expense should be included in the revenue requirement adopted by the Commission in this proceeding as a reasonable and prudently incurred expense.

Q137. Does this complete your direct testimony?

A137. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JEFFREY C. DAVIS

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric Company at the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic Business Operations.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (Company or DTE Electric).

Q3. What is your educational background?

A3. I graduated from the University of Michigan with bachelor's degrees in nuclear engineering and radiological sciences (NERS) and engineering physics. I have also earned a master's degree and doctorate in NERS from the University of Michigan.

Q4. Please summarize your professional experience.

A4. I have been employed by DTE Energy since 2008. Prior to my current position, I was Manager – Nuclear Strategy and Business Support with responsibility for developing the strategic financial plan and goals for the Nuclear Generation organization. From 2008-2015, I was a principal financial analyst with responsibility for budgeting, forecasting, and reporting operations and maintenance (O&M) and capital expenditures for the Nuclear Generation organization.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. I am a member of the American Nuclear Society.

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Q6. What are your current duties and responsibilities?

A6. I am responsible for advancing the strategic financial and operational plan and goals for the Nuclear Generation organization.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

U-20203	2018 Power Supply Cost Recovery (PSCR) Reconciliation
U-20528	2020 PSCR Reconciliation
U-20162	2018 DTE Electric Rate Case
U-20561	2019 DTE Electric Rate Case
U-20836	2022 DTE Electric Rate Case
U-21297	2023 DTE Electric Rate Case

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to discuss and support the reasonableness of the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2022. I will also discuss and support the reasonableness of the projected nuclear O&M and capital expenditures for the bridge forecast period and the 12-month projected test period ending December 31, 2025. In addition, I will discuss and support the reasonableness of the projected Nuclear Surcharge for the projected test period ending December 31, 2025.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.3	Projected Capital Expenditures - Nuclear Production Plant and Nuclear Fuel
A-13	C5.3	Projected Operation and Maintenance Expenses - Nuclear Power Generation
A-13	C5.16	Nuclear Power Generation - Projected PERC O&M Expenditures
A-20	J1	Proposed Nuclear Surcharge Projected Test Period – 12 Months Ending December 31, 2025
A-20	J2	Nuclear Plant Capital Project Detail – Routine and Small Projects

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How do you plan to proceed with your testimony?

A11. I will begin my testimony with the Nuclear Generation capital expenditures; discussing and supporting the actual capital expenditures for the historical test year ended December 31, 2022, the projected capital expenditures for the bridge forecast period and the 12-month projected test period ending December 31, 2025. I have divided my Nuclear Generation capital expenditure discussion into five sections of expenditures: Routine and Small Projects, Non-Routine and Large Projects, Nuclear Fuel, Allowance for Funds Used During Construction (AFUDC), and Plant Activity (removal costs, plant in service and CWIP).

I will then discuss and support the actual O&M expenses for the historical test year ended December 31, 2022 and the forecasted O&M expenses for the 12-month projected test period ending December 31, 2025 for Nuclear Generation. I have divided the Nuclear Generation O&M expenses discussion into three sections: rate case adjustments, adjusted historical test period and projected adjustments.

I will then discuss and support the Nuclear Surcharge for the 12-month projected test period ending December 31, 2025 for Nuclear Generation.

The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC) to operate through 2045. The capital and O&M expenditures discussed for the historical and projected test periods throughout my testimony reflect appropriate measures to ensure safe and reliable operation of the Fermi 2 Power Plant through 2045.

Nuclear Generation Capital Expenditures

Q12. Can you provide an outline of your Nuclear Generation capital expenditures discussion?

A12. My testimony will begin with the 2022 – 2025 Capital Projects Overview and then discuss and support the additional details regarding:

- Routine and Small Projects
- Non-Routine and Large Projects
- Total Nuclear Fuel
- AFUDC Forecast
- Plant Activity (Removal Costs, Plant in Service and CWIP)

2022 - 2025 Capital Projects Overview

Q13. Can you provide an overview of the Nuclear Generation capital expenditures you support?

A13. I refer you to Exhibit A-12, Schedule B5.3, page 1 which depicts the actual capital expenditures for the historical test year ended December 31, 2022, projected capital expenditures for the bridge forecast period and projected capital expenditures for the 12-month projected test period ending December 31, 2025.

Total capital expenditures are composed of Routine and Small Projects, Non-Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual capital expenditures for historical test year ended December 31, 2022, totaled

$257.8 million as shown on line 11, column (b) of the exhibit. Nuclear Generation forecasts total capital expenditures for the projected bridge forecast period at $451.5 million as shown on line 11, column (e) and for the 12-month projected test period ending December 31, 2025 at $215.9 million as shown on line 11, column (f).

I describe and support a portfolio of discrete reasonable and prudent projects and capital fuel expenditures which provides the basis for the historical actual and forecasted Total Capital Expenditures for January 1, 2022 through December 31, 2025.

Q14. How do the historical actuals for the 12-month period ending December 31, 2022, compare to the Nuclear Generation capital (including nuclear fuel) expenditures authorized for the same period in the U-21297 rate case?

A14. The U-21297 Order authorized Nuclear Generation capital expenditures at $258.7 million for the 12-month period ending December 31, 2022. The actual Nuclear Generation capital expenditures for the same period were $257.8 million. The total variance is approximately 0.3% of projected total Nuclear Generation capital expenditures for the reference period.

Q15. What was the Commission treatment of DTE Electric Nuclear Generation capital expenditures in U-21297 Order, dated December 1, 2023?

A15. DTE Electric's Nuclear Generation capital expenditures depicted in U-21297 were generally accepted and allowed for recovery.

However, the Commission also appropriately approved an accounting shift associated with Main Unit Generator Replacement project expenditures (depicted on line 2 of Exhibit A-12, Schedule B5.3, page 4) from rate base to construction work in progress (CWIP) because of the revised timing of the main unit generator installation. Final installation of the main unit generator has been moved from Refueling Outage 22 (RF22) (Spring 2024) to RF23 (Spring 2026).

Q16. Is it fair to conclude the Commission has already had the opportunity to review DTE Electric's Nuclear Generation historical actuals for the 12-month period ending December 31, 2022 in U-21297?

A16. Yes. When DTE Electric filed Case No. U-21297 in 2023, the projected 12-month period ending December 31, 2022, had included ten months of actuals and only two months of forecast. Most notably, as RF21 completed in May 2022, RF21 projects expenditures were complete, known and actuals already included in the expenditures depicted in U-21297 Exhibit A-12, Schedule B5.3; therefore, I will focus on highlighting projects that are more significant in the bridge and projected test years.

Q17. Before you discuss the discrete projects, can you summarize the principles and conduct of asset maintenance at a nuclear generation unit such as Fermi 2?

A17. Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the nuclear industry. Our operational and strategic decisions preserve this priority.

Q18. What do you mean by nuclear safety?

Line No.

A18. Nuclear safety is focused on ensuring that we maintain and operate the Fermi 2 nuclear asset with a high degree of rigor. Conservatism is necessary to minimize risk and ensure the safe and reliable use of nuclear material.

Q19. How does DTE Electric manage nuclear safety risk?

A19. DTE Electric manages nuclear safety risk through proper training, procedures and governance, operating the plant consistent with Fermi 2's Nuclear Regulatory Commission (NRC) operating license, operating the plant using the traits of a healthy nuclear safety culture (outlined in the World Association of Nuclear Operators (WANO) Principles PL 2013-1), and maintenance of the asset to support operation through 2045.

Q20. What are the key principles the DTE Electric organization uses for maintaining the nuclear asset?

A20. I would summarize our key maintenance principles as:

1. Implementation of inspection, surveillance, maintenance and project activities are proactive and condition- or time-based to preclude a failure. Unanticipated equipment failures challenge plant operators and result in unplanned shutdowns or derates of the unit; our strategies are designed to minimize the probabilities of unanticipated equipment failures.
2. Work such as capital replacements and modifications are implemented when the plant is in the safest condition to do so. For most of our work at Nuclear Generation, that safest condition is when the Fermi 2 plant is shut down for a refueling outage.

3. Work such as capital replacements and modifications are planned and executed in a reasonable and prudent manner consistent with the other key maintenance and project management principles.

Q21. Why is it safest to perform maintenance on the Fermi 2 plant during a refueling outage?

A21. Refueling outages are the safest time to perform maintenance for the following reasons:

1. Nuclear safety - our operating license issued by the NRC requires the plant to be shut down prior to taking many systems out of service for maintenance. These licensing requirements align with minimizing risks to health and safety.
2. Personnel safety – many areas of the plant are behind locked doors during operations due to the radiological or atmospheric conditions of the area. Refueling outages offer opportunities to access these otherwise inhospitable areas of the plant for maintenance.

Q22. What is the cadence for the Fermi 2 plant refueling outages?

A22. The Fermi 2 plant operates on a 24-month cycle, meaning every 24 months the Fermi 2 plant shuts down for a refueling outage. The Fermi 2 refueling outages are numbered sequentially and named as such: our winter/spring 2022 refueling outage, which was Fermi 2's twenty-first refueling outage, was named Refueling Outage 21 or RF21 and Fermi 2's twenty-second refueling outage scheduled in the spring of 2024 (approximately 24 months after RF21) is named Refueling Outage 22 or RF22.

Q23. What is the typical planning cadence for a Fermi 2 plant refueling outage?

A23. Refueling outages are highly complex and require an integrated work plan to execute thousands of activities in a relatively short duration.

Planning for a refueling outage is generally a two-year effort with many intermediate milestones guiding the planning effort; completion of these milestones requires consideration of the existing and projected material condition of the Fermi 2 Power Plant as well as any practical constraints for safe execution of the projected work. The two most relevant of these milestones for capital expenditures are (1) two years prior to the refueling outage (T-24 months), Nuclear Generation confirms the Non-Routine and Large Projects for implementation in the outage and (2) at one year prior to the refueling outage (T-12 months), Nuclear Generation confirms for the Routine and Small Projects to be completed in the outage.

Q24. How does the highly complex and integrated characteristic of refueling outage work impact project planning and execution?

A24. Projects implemented during refueling outages are not stand-alone, independent projects as one may typically think of projects.

For example, plant workers such as plant operators, radiation protection, building trades and supervision are not dedicated to individual projects but must be shared across different projects and maintenance because qualified nuclear professionals are finite, nuclear standards are exacting, and gaining clearance to work at a U.S. nuclear plant is non-trivial; suppliers performing work must be chosen to globally improve outage execution - selecting suppliers as if projects were independent

Line No.

would lead to more expensive work, unnecessary duplication of oversight and potential conflicts between suppliers.

As a second example, projects and maintenance activities may only occur in a specific schedule sequence which means performance of one project may impact performance of another project or projects.

As I said, this coordination of work and resources is important to finalizing refueling outage plans and takes place in the cycle leading up to the refueling outage.

Q25. How are suppliers chosen to globally improve work execution?

A25. Suppliers of nuclear equipment, components and services are relatively limited and serve a relatively small group of U.S. nuclear power stations. As of December 31, 2023, 93 U.S. commercial nuclear reactors were in commercial operations - and consolidation of suppliers is such that in many instances only one or two suppliers are qualified to provide certain nuclear components, equipment or services to nuclear power plants. Fermi 2 is further unique in that the plant is a General Electric Boiling Water Reactor Type 4 design (GE BWR/IV) with a Mark I containment structure and English Electric turbine/generator system. To be reasonable and prudent, selecting suppliers generally requires DTE Electric to weigh more than just the competitively bid costs: DTE Electric must consider supplier qualifications, safety record, original equipment manufacturer (OEM) status, incumbency, market share, industry operating experience and industry feedback, locality, ownership, union status and integration with the local building trades (if applicable), proposed schedule and costs, terms and conditions, likelihood of outcomes, amongst other factors. If a new participant enters a market, then supporting overall market competition can become a factor as well.

In general, DTE Electric secures long-term supplier agreements for Fermi 2 nuclear fuel, reactor services, turbine services, major maintenance services, heavy construction services, radiation protection services and engineering design services through competitive supplier sourcing and negotiation. Individual projects can then source, as needed, suppliers using these long-term agreements which facilitates each major supplier's resources being integrated into the overall work plan. DTE Electric sources other components, equipment and services in a reasonable and prudent manner consistent with the factors I outlined above.

Routine and Small Projects Capital Expenditures

Q26. Can you further explain the Routine and Small Projects summarized on line 2 of Exhibit A-12, Schedule B5.3, page 1?

A26. Routine and Small Projects are those capital expenditures associated with maintaining the various assets that support the safe operation of Fermi 2 and includes work such as pump, motor, valve and reactor control component replacements and can typically be expressed in number of units replaced. Routine and Small Projects are reasonable and prudent because these types of projects address commonly activated and used equipment that are the core of our proactive maintenance regime to maintain nuclear safety. Proactive replacement of these Fermi 2 components is essential to prioritizing nuclear safety by minimizing the potential for unanticipated or unrecoverable failures during plant operation.

Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small Projects that support page 1, line 2.

Q27. Can you explain the Routine and Small Projects detailed in Exhibit A-12, Schedule B5.3, pages 2-3?

A27. Exhibit A-12, Schedule B5.3, pages 2-3 show the by-project capital expenditures for Routine and Small Projects for the historical test year and the projected expenditures for the 24-month bridge forecast period ending December 31, 2024 and the 12-month projected test period ending December 31, 2025 which total $81.3 million, $135.2 million and $42.5 million respectively. Additional details for select routine and small projects are provided in Exhibit A-20, Schedule J2 and are also provided in the Part III (Questions 9 and 10) supplemental filing requirements.

The expenditures and project make-up are generally consistent each operating cycle and peak during refueling outage periods because of the regulatory and safety requirements governing Routine and Small Projects. I will highlight specific Routine and Small Projects to help convey the type of projects that comprise Routine and Small Projects in my testimony next.

Q28. Prior to discussing the highlighted projects, can you please generally discuss the capital expenditures for the historical year ending December 31, 2022, the projected bridge years ending December 31, 2023 and December 31, 2024, and the projected test year ending December 31, 2025?

A28. Historical year ending December 31, 2022 included Refueling Outage 21 (RF21). Most of the Small and Routine expenditures within the historical year ending

December 31, 2022 were associated with projects (such as the Visual Annunciator System replacement) that completed and went into service during RF21.

The projected bridge year ending December 31, 2023 is the year proceeding a refueling outage (RF22 in spring 2024); many of the project expenditures (such as control rod drive mechanism (CRDM) replacements) in 2023 are associated with planning, readying and material procurement for RF22.

The projected bridge year ending December 31, 2024 is the year that includes RF22 and, as such, most of the Small and Routine expenditures are associated with projects (such as the Residual Heat Removal Service Water (RHRSW) outlet valve (F068A/B) replacement) projected to be completed and go into service during RF22.

The projected test period ending December 31, 2025 is again a year that proceeds a refueling outage (RF23 in spring 2026), and similar to the projected bridge year ending December 31, 2023, many project expenditures (such as control rod drive mechanism (CRDM) replacements) in 2025 are associated with planning, readying and material procurement for RF23.

Q29. Does the general expenditure pattern just described apply to multi-year projects such as the Security System Computer replacement project shown on line 4, Plant Radio System project shown on line 5 on Exhibit A-12, Schedule B5.3, page 2, and Plant Wireless project shown on line 35 on Exhibit A-12, Schedule B5.3, page 3?

Line
No.

A29. No. Security System Computer, Plant Radio System and Plant Wireless projects are examples of multi-year Routine and Small Projects with predominately online implementation, so the general pattern of Routine and Small Projects expenditures just discussed is not as relevant to these projects. Because these projects are multi-year, I previously discussed these three projects in DTE Electric Rate Cases U-20836 and U-21297; nonetheless, because of their continued importance to our nuclear safety paradigm, I will again highlight these projects here.

Q30. Can you discuss the expenditures and rationale for the Security System Computer replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 4?

A30. The Security System Computer replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $7.1 million, $26.8 million and $0.0 million respectively and projects to complete prior to the end of the projected test period. This project addresses aging and obsolescence of the existing security system computer, and support the necessary replacement of the Fermi 2 Security System Computer which includes specialized computer servers, video cameras, other access control and detection devices, and communication cabling. This major plant security system is an aspect of the regulatory-required Fermi 2 Security Protection Plan per Code of Federal Regulation 10 CFR 73.55 which requires a physical security plan that must "ensure that the capabilities to detect, assess, interdict, and neutralize threats up to and including the design basis threat of radiological sabotage as stated in 10 CFR 73.1, are maintained at all times" and "provide defense-in-depth through the integration of systems, technologies, programs, equipment, supporting processes, and

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implementing procedures as needed to ensure the effectiveness of the physical protection program."

Q31. Why is replacement of the security system computer necessary within the projected test period?

A31. Components of the existing security system computer have exhibited decreased performance as service time has increased. Degradation of security equipment results in multiple alarms that distract the security force from core activities, requires compensatory measures which require unscheduled overtime, requires emergent maintenance, and increases the risk of gaps in meeting the regulatory requirements. In 2022, one of the intrusion detection systems accumulated three times more annual out of service time than it did in 2021, indicating a need to replace the system. Repair and replacement of existing components has become increasingly difficult as equipment becomes obsolete; for example, vendor supported software updates ceased for the security system computer's video monitoring software, video server operating system, and the server and workstation operating system in 2015, 2016 and 2020 respectively. Lack of vendor support for these operating systems or video monitoring systems could lead to extended loss of security video feeds which would require additional security personnel to compensate for the loss of video surveillance.

A security computer system used in the security of a nuclear power plant can be reasonably expected to be in service for approximately 10 – 15 years based on anticipated aging and obsolescence factors. Aspects of the Fermi 2 security system computer such as the communications cabling have been in service for more than thirty years; while the security system computer servers, workstations and access controls hardware is comparatively newer – this hardware still relies on late-2000s vintage technology. NRC cyber security regulations and the deeply integrated nature of the security system computer makes replacement components increasingly impractical to procure.

Preemptive replacement of the security system computer and its constituent components is a reasonable and prudent action, consistent with our nuclear safety priorities to support DTE Electric continuing to meet its regulatory commitments into the 2030s when DTE Electric anticipates the next routine replacement of the security system computer to occur. Several portions of this project also bring equipment and strategy up to nuclear industry standards. Additionally, these replacements will allow for more efficient equipment maintenance.

The integrated project also includes addition of equipment, for example, additional cameras, and changes to the location of some equipment to support satisfactory outcomes from NRC-graded Force-on-Force exercises as well as a formal assessment of the Security Strategy.

Q32. What is the role of the security computer system within the nuclear safety paradigm you discussed earlier in your testimony?

A32. The security computer system itself is an aspect of the Fermi 2 Physical Security Plan (the exact details of physical security plans are safeguarded and protected per regulation) – having and maintaining Fermi 2's security equipment in accordance with the approved physical security plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of hostile actors acting against a U.S. commercial nuclear plant are significant, each U.S. commercial nuclear site's physical security plan is routinely inspected and tested by the NRC to ensure compliance. DTE Electric has an obligation to ensure that all aspects of the Fermi 2 physical security plan work and will continue to work in the future – hence a preemptive replacement regimen is necessary to ensure components of the security computer system do not unexpectedly or unrecoverably fail.

As DTE Electric replaces the existing security computer system, Fermi 2 must remain in compliance with regulations such that: (1) the functions and capabilities of the existing security computer system must be maintained while the new system is being installed, (2) design, configuration control and work to replace the existing security computer systems must be performed so as to maintain operability of other Fermi 2 plant systems including taking special care when excavating to replace cabling and other components, (3) the new security computer system must meet NRC cyber security requirements, (4) the new system must be designed and tested for continuous operations with minimal maintenance time. Total project expenditures are commensurate with these regulatory requirements.

Q33. Was the Security System Computer project competitively sourced?

A33. Yes. Consistent with the commercial principles I discussed earlier, the Security System Computer project uses competitively-sourced suppliers. While commercial processes and agreements are sensitive information, DTE Electric provides relevant sourcing documents, subject to non-disclosure orders, within the natural order of this proceeding; other supplier and project information can be found in this proceeding's Part III, Attachment 9 supplement filing.

Total project costs reasonably and prudently reflect actual and projected costs based on the commercial solicitations and agreements. As I discussed earlier, commercial solicitation processes such as competitive sourcing is a principle of prioritizing nuclear safety to support safe, reliable and efficient project execution and post-implementation equipment operations.

Q34. Can you discuss the expenditures and rationale for the Plant Radio System replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 5?

A34. The Plant Radio System capital expenditures for the historical test year, projected bridge forecast period and the projected test period are $4.2 million, $7.5 million and $0.0 million respectively, do not extend beyond the projected test period, address security and operations vulnerabilities of the existing plant radio system, and support the necessary replacement of the Fermi 2 plant radio system which includes computers, radio repeaters, radio antenna, uninterruptible power supplies and communications cabling. This major system is an aspect of the regulatory-required Fermi 2 Physical Security Plan and the regulatory-required Fermi 2 Radiological Emergency Response Plan and has the purpose to be the primary means of communication for plant personnel including site security and fire brigade during operations and potential accident scenarios; loss of the plant radio system would degrade plant operators' ability to safely operate the Fermi 2 Power Plant.

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Q35. Why is replacement of the plant radio system necessary within the projected test period?

A35. Security and operations vulnerabilities. Replacement of the plant radio system began in 2017 with the replacement of plant radio equipment in the Fermi 2 Main Control Room (MCR); field radio communications to the MCR were becoming increasingly inaudible within the MCR which was unduly burdening plant operators during plant operations. Additionally, radio communications within the power plant uses an antenna system installed in the early 1980s, experiences a significant signal loss between the base station and the distributed antennas and is capable of transmitting only the UHS frequency band. Replacement of the plant radio system distributed antenna system, communications cabling and uninterruptible power supplies (which is the scope of work during the bridge and projected test periods in this case) will improve plant radio signal fidelity throughout the plant and add two additional radio frequencies bands (VHS and 800 MHZ) within the power plant.

Improving plant radio signal fidelity within the plant supports improved operations communications, especially for emergency responders such as fire brigade in all areas of the plant.

Adding the two additional radio frequency bands also allows DTE Electric to evaluate changes to the Fermi 2 Physical Security Plan, further improve Fermi 2's security posture and enhance security's communication capabilities with outside emergency responders such as the Michigan State Police.

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Q36. What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony?

A36. The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of an ineffective radiological emergency response are significant, each U.S. commercial nuclear site's emergency response plan is routinely inspected and tested by the NRC and the Federal Emergency Management Agency (FEMA) to ensure compliance. DTE Electric has an obligation to ensure that the components of the Fermi 2 Radiological Emergency Response Plan work and will continue to work in the future – hence a preemptive replacement regimen is reasonable and prudent.

The plant radio system is the primary communication means for plant operators and security officers responding to emergency conditions – unexpected or unrestorable failure or interruption of this equipment would be an unacceptable risk to first responders to any Fermi 2 plant emergency; it is imperative that the plant radio system maintains its capabilities throughout the plant and through all postulated operating scenarios.

As Fermi 2 replaces the existing plant radio system, the Company must remain in compliance with regulations such that: (1) the functions and capabilities of the existing plant radio system must be maintained while the new system is being installed, (2) design, configuration control and work to replace the existing plant radio system must be performed as to maintain operability of other Fermi 2 plant systems, (3) the new plant radio system must meet NRC cyber security requirements, and (4) the new system must be designed and tested for continuous operations with minimal maintenance time. This requires installing 16 new antennae and approximately 5800 feet of new conduit and cable. Total project expenditures are commensurate with these regulatory requirements.

Q37. Can you discuss the expenditures and rationale for the Plant Wireless project shown on Exhibit A-12, Schedule B5.3, page 3, line 35?

A37. The Plant Wireless project capital expenditures for the historical test year, projected bridge forecast period and the projected test period are $0.3 million, $7.7 million and $0.0 million respectively, do not extend beyond the projected test period, address operational vulnerabilities and support the replacement and expansion of the existing Fermi 2 plant wireless system which includes modems, network switches, and wireless antennae. The purpose of the plant wireless system is to provide wireless data communications capacity to plant personnel during normal operations; not replacing and expanding the plant wireless system would challenge operations to effectively operate the plant. In addition, the Plant Wireless project is resource-optimized with the Plant Radio System replacement project by sharing the conduit and cable trays.

Q38. What is the role of the plant wireless system within the nuclear safety paradigm you discussed earlier in your testimony?

A38. Installation of a wireless communication backbone throughout the nuclear power block directly impacts the ability to progress with other cost-savings and radiological dose-savings initiatives including Electronic Work Orders, Electronic Operator Rounds, remote dose monitoring and remote equipment monitoring. NRC regulations require management measures which include configuration management, maintenance, training and certification, procedures, records management, and other quality assurance methods, generally on a continuing basis, that are applied to items relied on for safety, to ensure the items are available and reliable to perform their functions when needed. Plant wireless system provides the networking infrastructure and capacity necessary for Fermi 2 to modernize and maintain these management measures. Plant wireless networks are used in the nuclear industry to provide efficiency in recording and automatically storing regulatory-required documentation and for additional monitoring of equipment important to nuclear safety and plant reliability without incurring the large costs of permanent imbedded cabling.

Existing management measures require controlled paper copies of work orders, plant drawings, engineering design documents, purchasing agreements, time sheets and procedures in the field – not that different from when the Fermi 2 first started commercial operations in 1988. While these paper-document management measures continue to support safe and reliable operations, modern industry-best practices have evolved to use paperless work orders and procedures, automated document control and records management, and electronic time keeping systems to reduce human error precursors and to maintain positive configuration control of the plant.

As DTE Electric replaces and expands the existing plant wireless system, the Company must remain in compliance with regulations such that: (1) design, configuration control and work to replace and expand the existing plant wireless system must be performed so as to maintain operability of other Fermi 2 plant systems, (2) wireless network signals from the plant wireless system must strike a difficult engineering balance between strong signal strength and bandwidth against requirements that the signals not interfere with the function of other plant equipment and (3) the new plant wireless system must meet NRC cyber security requirements. Total project expenditures are commensurate with these regulatory requirements.

Q39. What do you mean by "aging and obsolescence?"

A39. Aging in the context of nuclear plant operations refers to the general process in which characteristics of equipment or components gradually degrade with time or use.

Component obsolescence in the context of nuclear plant operations refers to equipment or components that are no longer manufactured or qualified by their original manufacturers.

Q40. Why is obsolescence a particular concern for DTE Electric at the Fermi 2 Power Plant?

A40. I have discussed aging and obsolescence a few times already because aging and obsolescence concerns are not just a focus for DTE Electric, but a focus for the entire U.S. nuclear industry. Configuration management at a nuclear power plant specifies allowed components by manufacturer and model number. Once manufacturers cease operations, change ownership or cease production of a particular model, nuclear operators must identify potential replacements. This process of identifying potential replacements is rigorous as all aspects of the potential replacement's fit, form and function must be evaluated by qualified engineers. Potential replacements may also require physical modification to the plant to be usable – Security System Computer is one such project that requires modifications to the Fermi 2 plant to address aging and obsolescence.

Unexpected or unrecoverable failures of obsolete components are a vulnerability to safe and reliable plant operations. Of course, as components age, the vulnerability of unrecoverable failure increases. Unexpected or unrecoverable failures of obsolete components could result in the extended compensatory measures that burden operations, security, or other plant personnel; shutdown of the plant is also a possibility until potential replacements are identified and actions are taken to make the replacement usable within the plant.

Q41. What actions must a nuclear operator such as DTE Electric take to physically modify the plant?

A41. When new or replacement components or equipment require a plant modification, in addition to the physical field work of the modification there are several management actions required: (1) plant drawings and component databases must be updated, (2) plant calculations must be revised to ensure sufficient structural loading or electrical loading margins exist, (3) physical security and emergency response plans must be evaluated and possibly revised, (4) operating license and safety analysis reporting must be evaluated and possibly revised, and (5) training, operations and maintenance programs must be evaluated and possibly revised.

The resources, time, and costs of these regulatory-required management measures are non-trivial.

Q42. Can you discuss the expenditures and rationale for the Undervessel Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 2?

A42. I previously discussed the routine Undervessel Replacements project, as well as the related projects involving Control Rod Blade Replacements and Control Rod Drive Mechanisms Replacements, in Case No. U-21297. DTE Electric has depicted the ongoing and updated capital expenditures for these projects in each DTE Electric rate case dating back to at least U-16472 without contention. I would like to again establish the importance of these Routine and Small Projects with a discussion here, starting with the Undervessel Replacements project. The Undervessel Replacements capital expenditures for the historical test year, projected bridge forecast period and projected test period are $8.0 million, $6.6 million, and $0.0 million respectively. These expenditures do extend beyond the projected test period and through the balance-of-life of the Fermi 2 Power Plant, address component aging, and support the necessary replacement of undervessel components which include control rod drives and nuclear instrumentation such as local power range monitors (LPRMs). The purpose of undervessel components goes to the heart of safely operating a nuclear reactor and directly affects control and monitoring of power levels throughout the reactor core (undervessel components are so named because the components are driven by equipment located underneath the reactor pressure vessel); unplanned or unrecoverable loss of these components would challenge plant operator's ability to safely operate the Fermi 2 plant.

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Q43. Can you discuss the expenditures and rationale for the Control Rod Blade Replacements project shown on Exhibit A-12, Schedule B5.3, page 3, line 45?

A43. The Control Rod Blade (CRB) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.1 million, $1.0 million, and $0.9 million respectively, do extend beyond the projected test period and through the balance-of-life of the Fermi 2 Power Plant, closely relates to the Undervessel Replacements projects, address CRB component aging, and support the necessary replacement of the CRBs (DTE Electric replaced 19 CRBs in RF21 and projects replacement of 22 CRBs in RF22). The purpose of Fermi 2's 185 CRBs is to control power levels within the reactor core and to ultimately safely accomplish shut down of the reactor when appropriate; unplanned or unrecoverable loss of the CRBs would challenge plant operator's ability to safely operate the Fermi 2 plant.

Q44. Can you discuss the expenditures and rationale for the Control Rod Drive Mechanisms project shown on Exhibit A-12, Schedule B5.3, page 2, line 28?

A44. The Control Rod Drive Mechanism (CRDM) replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.9 million, $5.2 million, and $4.9 million respectively, do extend beyond the projected test period and through the balance-of-life of the Fermi 2 Power Plant, closely relates to the Undervessel Replacements projects, address CRDM component aging, and support the necessary replacement of the CRDMs (DTE Electric replaced 20 CRDMs in RF21 and projects replacement of 20 CRDMs in RF22 and 20 CRDMs in RF23 (spring 2026)). The purpose of Fermi 2's 185 CRDMs is to control power levels within the reactor core and to ultimately safely accomplish shut down of the reactor upon receiving either manual or automatic signals; unplanned or unrecoverable loss of the CRDMs would challenge plant operator's ability to safely operate the Fermi 2 plant.

Q45. Why is Fermi projecting to replace 22 CRBs in RF22 and only 20 CDRMs in RF22?

A45. Although CRBs and CRDMs are part of the same control rod drive system, the aging mechanism is very different between CRDMs and CRBs. CRDMs (hydraulic piston assemblies located underneath the reactor pressure vessel) are subject to harsh environmental conditions such as extreme heat, moisture and radiation; after time, the components of the CRDM will naturally stress, fatigue and wear and must be replaced. CRBs (crucible-shaped, metal-tube components that contain a neutron-absorbing material located inside the reactor core adjacent to fuel assemblies) are subject to the extreme environment of the reactor itself; after time, the neutron-absorbing material is consumed preventing it from fully performing its function to shutdown the reactor or the CRB structural material will stress, fatigue and wear and may become damaged during operation which could directly impact fuel integrity.

Each component of the control rod drive system must be evaluated and replaced on its own schedule. For CRBs, DTE Electric determines this schedule based on analysis of the operational history of the individual CRBs, calculates remaining useful core life, and performs confirmatory testing to ensure the CRBs perform as expected. For CRDMs, DTE Electric levelizes the replacements of the CRDMs over their approximately 12-cycle in-service life.

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Q46. What is the status of the commercial agreements for the Undervessel Replacements, CRBs and CRDMs?

A46. DTE Electric has negotiated long-term commercial agreements (using the commercial principles I discussed earlier) for the OEM suppliers to provide these vital nuclear components and services through at least 2027. These long-term agreements provide DTE Electric with high assurance of adequate supply of nuclear-quality plant components at predictable quality, compatibility and cost – which is certainly reasonable and prudent.

Q47. What are the expenditures and rationale for the Roof Replacements project shown on Exhibit A-12, Schedule B5.3, page 3, line 51?

A47. The Roof Replacements project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $3.3 million, and $0.0 million respectively with complete replacements of the Office Building Annex (OBA), Office Service Building (OSB), and Warehouse A roofs already complete in 2023. Of course, DTE Electric projects other roofs to be replaced in the future but those future project expenditures would occur beyond 12-month projected test period ending December 31, 2025 and are not included in this proceeding.

Q48. Why was replacement of these roofs necessary in 2023?

A48. Aging. The roofs in scope are original to the plant and leaked and further repair was constrained by their antiquated design. The Fermi 2 OBA and OSB house nuclear operations staff, work control, outage management staff and maintenance staff as well as the Fermi 2 maintenance shops (Mechanical, Electrical and Instrument &

Controls (I&C) and machine shop). Warehouse A is the warehouse within the Fermi 2 Protected Area used for staging parts and materials for upcoming work.

Q49. What is the role of the Roof Replacements project within the nuclear safety paradigm you discussed earlier in your testimony?

A49. All workers – at a nuclear power plant or otherwise, should be able to work in an environment safe from industrial hazards such as leaking roofs.

Our U.S. nuclear industry refers to workers at nuclear power plants as "nuclear professionals." Our industry places considerable expectations on nuclear professionals and appropriately so given the obligation to safely operate nuclear power plants. One of these expectations is that nuclear professionals are to practice good housekeeping and control of work areas to minimize the potential for injuries, likelihood of human error, the spread of contamination and the generation of nuclear waste; tolerating leaking roofs, which have the potential to undermine any of the aspects of the expectation I just outlined risks undermining a criterion of nuclear professionalism – which would not be reasonable and would not be prudent.

Non-Routine and Large Projects Capital Expenditures

Q50. Can you discuss the Non-Routine and Large Projects summarized on line 3 of Exhibit A-12, Schedule B5.3, page 1?

A50. Non-Routine and Large Projects are projects that are necessary to properly maintain the Fermi 2 asset and are incremental to normal routine capital expenditures.

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Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that support page 1, line 3.

Q51. Can you explain the Non-Routine and Large Projects detailed in Exhibit A-12, Schedule B5.3, page 4?

A51. Yes. This exhibit shows the by-project capital expenditures for Non-Routine and Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These projects for the historical test year, the projected expenditures for the 24-month bridge forecast period ending December 31, 2024 and the 12-month projected test period ending December 31, 2025 total \$173.2 million, \$204.3 million and \$38.4 million respectively. A discussion of certain Non-Routine and Large Projects follows with additional details for other Non-Routine and Large Projects provided in the Part III (Questions 9 and 10) supplemental filing documents.

Q52. Can you explain the expenditures and rationale for the Main Unit Generator projects shown on line 2 and line 5 of Exhibit A-12, Schedule B5.3, page 4?

A52. The main unit generator projects are a series of replacements necessary to address both an Original Equipment Manufacturer (OEM) design vulnerability and improve overall reliability through 2045. These projects also support electrical grid reliability. Replacement of this model of generator is the identical approach other nuclear generation owners have taken over the years to mitigate operational risk. To support reliable operation of Fermi 2 through 2045, major refurbishments and replacement of the existing generator asset is reasonable and prudent. The replacement main unit generator stator, as of January 2024, is at the manufacturing facility in New York. Work is ongoing to ready the replacement main unit generator stator. DTE Electric will continue to make reasonable and prudent decisions to ensure the main unit generator project, once complete, will support safe and reliable operations through Fermi 2's operating license termination date in 2045.

The Main Unit Generator rotor replacement project as depicted on line 5 replaced the existing main unit generator rotor with a refurbished spare rotor during RF21. This replacement was performed to mitigate operational vulnerabilities associated with the existing main unit generator. This replacement occurred during RF21 and has capital expenditures for the historical test year, projected bridge forecast period, and projected test period of $15.9 million, $0.0 million and $0.0 million respectively.

The Main Unit Generator Replacement project as depicted on line 2 is to replace the generator stator and rotor with a matched stator and rotor. This replacement is projected to occur during RF23 (Spring 2026) and has capital expenditures for the historical test year, projected bridge forecast period and projected test period of $47.1 million, $87.9 million and $14.3 million respectively.

Q53. Why was the Fermi 2 main unit generator rotor replaced in RF21?

A53. The Midcontinent Independent System Operator (MISO) identified that Trenton Channel Unit 9 would be designated as a System Support Resource (SSR) (and thus would be required to continue to be operable and not eligible for retirement) unless an alternative solution was identified to resolve violations of applicable reliability criteria upon the unit's retirement. Replacement of the existing Fermi 2 main unit generator rotor (and the generator excitation automatic voltage regulator (AVR)

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depicted on line 6 of Exhibit A-12, Schedule B5.3, page 4) was required in conjunction with replacement of Service System Transformer #65 (depicted on line 7 of Exhibit A-12, Schedule B5.3, page 4) prior to retirement of the Trenton Channel Power Plant in May of 2022 to resolve the reliability issues that would otherwise occur. The Fermi 2 generator rotor and AVR that were in-service prior to RF21 were not capable of generating sufficient reactive power to solve the reliability issues identified by MISO. RF21 was the Company's last window of opportunity to replace the Fermi 2 generator rotor to maintain the Trenton Channel Unit 9 planned 2022 retirement date as required by the 2020 Consent Decree between the Company and the United States Environmental Protection Agency[1].

Q54. What is the basis to replace the Fermi 2 main unit generator in RF23?

A54. The existing Fermi 2 generator (stator) is the original plant equipment, manufactured in the early 1970s using the technology of that time. The generator stator is approaching end of life (EOL). To date, multiple known vulnerabilities and degradation have been mitigated through increased maintenance bridging strategies; however, design vulnerabilities associated with the stator continue to represent increased risk for sudden failure. Unplanned or unexpected failures not only present a generation risk but also present operational risk to the plant operators responsible for maneuvering the plant to a shutdown condition following a generator failure.

A matched rotor will be installed in RF23 for two reasons: (1) a matched rotor can be fit with the replacement stator prior to field work during RF23 which minimizes project execution risk and (2) the current rotor installed in RF21 may be

[1] https://www.justice.gov/enrd/consent-decree/file/1276421/download, accessed January 6, 2024.

contaminated with metallic particles after use with the original stator and its design flaw which could jeopardize the integrity of the replacement stator if the current rotor were to be reinstalled.

DTE Electric continues the necessary work to complete the replacement stator and have the replacement main unit generator (stator and rotor) in a ready state. Implementing the Main Unit Generator Replacement project in RF23 is a reasonable and prudent action because of the current state described above. DTE Electric has implemented and will continue to implement reasonable and prudent bridging strategies to mitigate the short-term reliability risks associated with the existing Fermi 2 main unit generator; however, given the main unit generator's importance with respect to safe and reliable plant operations through 2045, DTE Electric has scheduled implementation of the Main Unit Generator Replacement project in RF23.

Q55. What specific work is being performed at the manufacturer facility in New York?

A55. Subsequent inspections of the new generator stator revealed unsatisfactory foreign material within the coatings applied to the stator. The generator stator has been completely disassembled, and the coatings were removed. The stator parts were then reinspected, recoated and reassembled.

Q56. Why did the projected in-service date for the Main Unit Generator Replacement project change from RF22 (2024) in U-21297 to RF23 (2026) in this proceeding?

A56. Transportation from the manufacturing facility in New York to the Fermi 2 Power Plant is performed via the St Lawrence Seaway. The Seaway and canals are generally closed to shipping during the winter months. Rather than attempt to use higher risk transportation methods or routes to support a delivery date that fully supported sufficient time to ready the replacement generator for RF22 install, DTE Electric made a well-reasoned and prudent decision to change the generator replacement to RF23.

Q57. Can you discuss the expenditures and rationale for the Underground Safety-Related Service Water Piping project shown on line 4 of Exhibit A-12, Schedule B5.3, page 4?

A57. The Underground Safety-Related Service Water Piping capital expenditures for the historical test year, projected bridge forecast period and projected test period are $23.3 million, $42.9 million and $0.0 million respectively. The Underground Safety-Related Service Water Piping project replaces nuclear safety-related piping that delivers cooling water to various components that support the operation of the nuclear reactor. A portion of the underground safety-related service water piping was replaced in RF21, with the remaining piping to be completed in RF22. The replacement of the underground safety-related service water piping is necessary to address age-related degrading pipe-wall thickness and to ensure this pipe will continue to support plant operations through the end of the operating license in 2045.

Q58. What does it mean to be "safety-related" piping?

A58. In the U.S. nuclear industry, the term "safety-related" applies to systems, structures, components, procedures, and controls that are relied upon to remain functional during and following design-basis events. Per NRC regulations, materials, equipment and components of safety-related systems have very strict manufacturing tolerances and quality control; new materials, equipment and components are inspected against technically developed procurement specifications. Post-delivery modifications to safety-related materials such as cutting, fitting and welding pipe must be to design, properly controlled, traceable, and work inspected by qualified inspectors. Work on safety-related equipment requires an exactness in performance that is not common in non-nuclear industry.

Q59. Can you discuss the expenditures and rationale for the General Service Water (GSW) intake groin replacement shown on line 20 of Exhibit A-12, Schedule B5.3, page 4?

A59. The General Service Water (GSW) intake groin replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $18.0 million, and $0.0 million respectively, do not extend beyond the projected test period, address natural erosion of the existing GSW intake groin structure, and support the necessary replacement of the GSW intake groin structure. The Fermi 2 GSW intake groin structure is comprised of two armored-earthen jetties that jut into Lake Erie; the jetties' armor is rock and concrete tetrapods which are designed to mitigate Lake Erie erosion action and yet allow enough movement within the armor structure itself to mitigate Lake Erie ice action from damaging the armor. The purpose of Fermi 2 GSW intake groin structure is to protect the Fermi 2 GSW intakes from Lake Erie wave action, minimize bio-material accumulation at the GSW intake and to minimize sediment accumulation at the GSW intake; the Fermi 2 GSW system itself provides cooling

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water to plant equipment; unplanned or unrecoverable loss of the GSW would challenge the plant operator's ability to safely operate the Fermi 2 plant.

Q60. Can you discuss the expenditures and rationale for the License Renewal Implementation (LRI) project shown on line 8 of Exhibit A-12, Schedule B5.3, page 4?

A60. The License Renewal Implementation (LRI) project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$5.8 million, \$15.3 million, and \$0.7 million respectively, do extend beyond the projected test period, address DTE Electric's NRC renewed operating license commitment, and support the necessary first-time and only-time inspection required from Fermi 2 to operate during its Period of Extended Operations which begins in 2025. To ensure safe operations during a plant's Period of Extended Operation, the NRC mandates programs to monitor and intrusively inspect passive plant systems that may be impacted by plant age; the Fermi 2 LRI project coordinates and conducts the first-time and one-time inspections associated with this new and regulatorily-required monitoring and inspection regime; failure to complete these first-time and one-time inspections would result in NRC violations and possible suspension of Fermi 2's renewed operating license.

Q61. Can you discuss the expenditures and rationale for the Circulating Water (CW) Discharge Pipe project shown on line 9 of Exhibit A-12, Schedule B5.3, page 4?

A61. The Circulating Water (CW) Discharge Pipe project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$5.3 million, \$0.0 million, and \$0.7 million respectively, extend beyond the projected test period, address natural aging of the Fermi 2 CW discharge piping, and support the necessary in situ replacement of the CW discharge piping pressure boundary with a carbon-fiber shell that lines the interior surface of the CW discharge pipe. The Fermi 2 CW piping is two interconnected sets of underground 144" diameter, pre-stressed concrete cylinder pipe (PCCP); total pipe length is approximately a mile and comprised of approximately 450 pipe segments. The purpose of Fermi 2 CW piping is to transport circulating water from the CW pond to the Main Unit Condenser (CW inlet piping) and to transport the circulating water from the Main Unit Condenser to the Fermi 2 natural draft cooling towers (CW discharge piping); the Fermi 2 CW system itself provides cooling water to Main Unit Condenser; unplanned or unrecoverable loss of the CW piping would challenge plant operator's ability to safely operate the Fermi 2 plant and cause a unit shutdown.

Q62. Why is it necessary to replace the pressure boundary of the CW discharge piping?

A62. The CW pipe is original to plant construction and is aging – as all underground concrete pipes do. The PCCP has a concrete core, a thin steel cylinder, high tensile prestressing wires and a mortar coating. As PCCP ages the mortar will delaminate exposing the prestressing wires to corrosion forces; as the prestressing wires corrode, the strength of the PCCP deteriorates and the PCCP will catastrophically fail.

Because the failure mode of PCCP is catastrophic failure, the reaction time of plant operators to safely maneuver the plant is greatly reduced. DTE Electric is taking the reasonable and prudent approach to perform in situ replacement of the interior CW pipe pressure boundary with a carbon-fiber liner, pipe segment by pipe segment, over time and in stages based on priorities derived from inspections to minimize refueling outage time.

Q63. Can you discuss the expenditures and rationale for the Feed Water Heaters Replacements project shown on line 10 of Exhibit A-12, Schedule B5.3, page 4?

A63. The Feed Water Heaters Replacements capital expenditures for the historical test year, projected bridge forecast period and projected test period are $4.9 million, $11.1 million and $4.7 million respectively. The Feed Water Heaters Replacements project replaces six of Fermi 2's twelve feed water heaters that condition the nuclear feed water for return to the reactor core. The six feed water heaters will be replaced during RF23 (spring 2026) and RF24 (spring 2028); the remaining six feed water heaters experience less operational stress and do not require replacement at this time. The replacement of these feed water heaters, which are original plant equipment, is necessary to address normal end-of-life degradation and improve operational margins. Additionally, internal degradation of the existing feed water heaters contributes to radiological dose rates in the plant. The new feed water heaters are being constructed from materials that, as they wear and degrade during operation, will not contribute radiological dose.

Q64. Are there logistical complexities associated with the replacement of the feed water heaters?

A64. These feed water heaters are quite large (i.e. approximately the size of a semi-trailer and weighing between 80,000 and 130,000 pounds each) and located in enclosed rooms within Fermi 2 Turbine Building, surrounded by pipes. To get these feed

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water heaters into the Turbine Building requires disassembly of the east wall of the Turbine Building and relocation of structures within the building. Additionally, each of the piping interferences must be removed from the feed water heater rooms to allow the existing feed water heaters enough space to be removed and new feed water heaters moved into place; the interference piping must then be restored along with the Turbine Building wall prior to unit startup.

Q65. Can you discuss the expenditures and rationale for the drywell cooler projects shown on lines 11, 16 and 18 of Exhibit A-12, Schedule B5.3, page 4?

A65. These drywell cooler projects are part of a staged, multi-year effort to proactively and systematically address a series of necessary drywell cooler replacements in a manageable fashion based on risk of potential leakage. The replacements have been grouped by refueling outage implementation. The replacement of these coolers is necessary to address the normal end of life status and degradation of these coolers which are original plant equipment. Excessive leakage from drywell coolers can and have resulted in plant shutdowns to repair. Fermi 2 has 14 drywell coolers which provide the containment structure that surrounds the reactor with atmospheric cooling during normal operations.

Drywell Coolers #10 and #14, as depicted on line 18, were replaced in RF20 in the spring of 2020 and have capital expenditures for the historical test year, projected bridge forecast period and projected test period of $0.0 million, $0.0 million and $0.0 million respectively.

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Drywell Coolers #12 and #13, as depicted on line 11, were replaced in RF21 and have capital expenditures for the historical test year, projected bridge forecast period and projected test period of $3.5 million, $0.0 million and $0.0 million respectively.

Drywell Cooler #8 is depicted on line 16, is forecasted to be replaced in RF23 and has capital expenditures for the historical test year, projected bridge forecast period and projected test period of $1.5 million, $0.0 million and $0.6 million respectively.

Q66. Are there additional complexities associated with the replacement of the drywell coolers?

A66. The drywell coolers are located in the Fermi 2 drywell. The drywell immediately surrounds the reactor pressure vessel and its environment is typically characterized by high temperatures, radiologically contaminated surfaces and significant radiological dose presence with densely configured plant equipment; while sealed from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated using potentially complex lifting and rigging evolutions or removed and later reinstalled to successfully replace the coolers. Work must be highly scripted by qualified individuals to address plant configuration challenges, minimize radiological dose, and minimize human performance errors.

Q67. Can you discuss the expenditures and rationale for the Boraflex Fuel Storage Racks project shown on line 12 of Exhibit A-12, Schedule B5.3, page 4?

Line No.

A67. The Boraflex Fuel Storage Racks capital expenditures for the historical test year, projected bridge forecast period and projected test period are $3.4 million, $4.0 million and $0.0 million respectively. The Boraflex fuel storage racks project will replace the end-of-life Boraflex fuel storage racks with new neutron-absorbing material. The replacement of the Boraflex fuel storage racks is an NRC commitment tied to Fermi 2's license renewal and is necessary to restore safety margins for the storage of the spent fuel through the end of the operating license in 2045.

Q68. Can you discuss the expenditures and rationale for the Radiation Monitors project shown on line 13 of Exhibit A-12, Schedule B5.3, page 4?

A68. The radiation monitors capital expenditures for the historical test year, projected bridge forecast period and projected test period are $2.7 million, $13.2 million and $2.6 million respectively. The Radiation Monitors project replaces Fermi 2's radiation monitor computer referred to as "SS1," as well as the plant's SPING (detects particulate, iodine and noble gases) and AXM (accident range effluent monitor) radiation monitors; together this radiation monitor system monitors and analyzes the plant's gaseous effluents to affirm the plant's radiation levels remain within proper specification. This radiation monitor system is credited in Fermi 2's Emergency Response Plan due to its capacity to monitor and analyze potential radioactive releases thus directly impacts recommendations provided to the state for instituting emergency actions for the public in the event of an emergency. The radiation monitor system will be replaced in phases throughout the bridge and test period and is expected to be completed in 2025. The replacement of this radiation monitor system is necessary to address aging and obsolescence, reduce the resource and dose impact of compensatory sampling, and improve regulatory margins;

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unexpected or unrecoverable loss of this radiation monitor system could result in NRC enforcement action.

Q69. Can you discuss the expenditures and rationale for the Fire Header Restoration project shown on line 17 of Exhibit A-12, Schedule B5.3, page 4?

A69. The Fire Header Restoration project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$0.8 million, \$4.0 million, and \$0.0 million respectively, extend beyond the projected test period, address natural aging of the Fermi 2 fire header piping, and support the necessary replacement of the Fermi 2 fire header piping. The Fermi 2 fire header piping is approximately 5000' of underground "ring header" comprised of 12" unlined, ductile iron pipe that routes around the Fermi 2 Power Plant and a separate 6" header for the station blackout diesels. The purpose of Fermi 2 fire header is to distribute firefighting water from the normal or alternate sources of water to the scene of a postulated fire; with fire being one of the most consequential events at a nuclear power plant, unplanned or unrecoverable loss of the fire header piping would challenge plant operator's ability to safely operate the Fermi 2 plant.

Q70. Why is it necessary to replace the Fermi 2 fire header?

A70. Normal aging. The fire header pipe is original to plant construction and is approaching fifty years of in-service time. As a fire header, the piping is exposed to raw lake water which degrades the interior surfaces of the pipe, causing leaks and loss of water pressure. The existing fire header pipe would not support safe and reliable operations through Fermi 2's current operating life ending in 2045. DTE Electric is taking the reasonable and prudent approach to replace the fire header pipe over time and in stages based on priorities derived from inspection and testing; this also allows for minimal fire header outage time and minimal operational compensatory measures to protect the plant while replacement is occurring.

Q71. Can you discuss the expenditures and rationale for the Fire Detection System Replacement project shown on line 24 of Exhibit A-12, Schedule B5.3, page 4?

A71. The Fire Detection System Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $2.3 million, and $1.3 million respectively, extend beyond the projected test period, address obsolescence of the Fermi 2 fire detection system, and support the necessary replacement of the Fermi 2 fire detection system. The Fermi 2 fire detection system consists of detection and annunciation systems. The purpose of the Fermi 2 fire detection system is to detect fire and signal fire alarms, and is designed to supplement Fermi 2's other fire safeguards such as design, procedures and behaviors; with fire being one of the most consequential events at a nuclear power plant, unplanned or unrecoverable loss of the fire detection system would challenge plant operator's ability to safely operate the Fermi 2 plant.

Q72. Can you discuss the expenditures and rationale for the Reactor Recirculation Motor-Generator (RRMG) Replacements project shown on line 26 of Exhibit A-12, Schedule B5.3, page 4?

A72. The Reactor Recirculation Motor-Generator (RRMG) replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are $0.0 million, $0.0 million, and $6.2 million respectively, extend beyond the projected test period, address aging of the two Fermi 2 RRMG sets, and support the necessary replacement of the Fermi 2 RRMGs. The existing Fermi 2 RRMGs consist of an RRMG motor, fluid coupler, oil system, generator and scoop tube positioner. The purpose of the Fermi 2 RRMG sets is to provide variable power to the Fermi Reactor Recirculation System (RRS) pump motors, one RRMG set controls one RRS pump motor.

Q73. Why is it necessary to replace the Fermi 2 RRMG sets?

A73. Primarily aging. The RRMG motor rotors, in particular have been in service since plant start up in the 1980s and have increasing risk of developing shorts as in-service time extends past 30 years. The Fermi 2 RRMG sets use complex mechanical interactions to vary voltage to the RRS motors, and though this system had wide spread usage when plants similar to Fermi 2 were built, the vast majority of US Boiling Water Reactors (BWRs) have replaced the mechanical RRMG sets with solid-state devices known as Variable Frequency Drives (VFDs), also known as Adjustable Speed Drives (ASDs); these VFDs are mechanically simpler than RRMGs, have developed a history of reliable operation, and use significantly less house power to operate. DTE Electric is projecting to replace the Fermi 2 RRMG sets in Refueling Outage 24 (Spring 2028).

Q74. Can you discuss the expenditures and rationale for the Sanitary System replacement project shown on line 28 of Exhibit A-12, Schedule B5.3, page 4?

A74. The Sanitary System replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$0.0 million, \$0.0 million, and \$6.5 million respectively, extend beyond the projected test period, address aging and undersized piping, and support the necessary replacement of the

Fermi sanitary system. The sanitary wastewater system is designed to dispose of nonradioactive plant sewage liquid waste in accordance with state and local regulations and consists of piping and a pumping station. The current pump house, which was originally built to support Fermi 1 operations, consists of a septic tank, settling Tank, wet well, and pumps to transfer sewage around the facility and to discharge out the forced main; however, the pumps are not designed to pump solid waste and the concrete structure is in need of repair or replacement - due to the location, a failure of the structure risks a release into Lake Erie. The sanitary system project replaces this antiquated sanitary wastewater disposal with a more modern two pump system capable of safely disposing of Fermi 2's sanitary wastewater.

Q75. Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain contingency amounts?

A75. No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4 do not include contingencies. The capital expenditures shown in Exhibit A-12, Schedule B5.3, pages 2-4 are good faith estimates (without contingencies) based on relevant data available using reasonable and prudent forecasting methods.

Q76. Does the absence of contingency amounts in Exhibit A-12, Schedule B5.3, pages 2-4 impact individual project expenditure variances from DTE Electric rate case to rate case?

A76. Certainly. The need for and use of contingency amounts at the individual project level and at the portfolio level is well understood in project management and portfolio management. Because DTE Electric's Nuclear Generation projects don't include contingencies, some known scope with highly uncertain costs have projected expenditures excluded from exhibits (such as the Security Computer Replacement project) until such time the expenditures are capable of being identified with reasonable specificity to include in the exhibit; therefore, projects expenditures will necessarily change as less defined scope and previously excluded expenditures transition into better identified and included expenditures. This is a reasonable and prudent approach in light of the expectation to exclude contingency amounts from DTE Electric's rate case exhibits and subsequent revenue requirements.

Q77. How does the Nuclear Generation organization manage its capital expenditures without contingencies?

A77. Nuclear Generation manages total capital expenditures for the period and expects that capital expenditures in total will be incurred as projected. In general, Nuclear Generation maintains a prioritized list of projects such that as project forecasts are over or under expected amounts, Nuclear Generation uses this prioritized list consistent with the key principles I described earlier to manage the Nuclear Generation portfolio of projects.

<u>Nuclear Fuel Capital Expenditures</u>

Q78. Can you explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12, Schedule B5.3, page 1?

A78. Yes. Total Nuclear Fuel includes those capital expenditures for the various components of the nuclear fuel cycle: (1) Uranium, (2) Conversion, (3) Enrichment and (4) Fabrication.

Uranium refers to the costs associated with mining and milling uranium. Natural uranium is obtained from the exploration and mining of uranium ore. Milling is the mechanical and chemical process of extracting uranium from the mined ore in the form of U3O8, commonly referred to as yellowcake. The U3O8 is the feed material for the conversion process.

Conversion refers to the costs associated with chemically converting U3O8 into UF6, uranium hexafluoride. The UF6 is the gaseous compound used as a feed in the enrichment process.

Enrichment refers to the costs to enrich the uranium from a natural 0.7% U235 content to a 4% to 5% U235 content required for light water reactor fuel. The enriched UF6 is used as a feed in the fabrication process.

Fabrication refers to the chemical conversion of the enriched UF6 to UO2 (uranium dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods are then assembled into fuel bundles using spacers and end fittings to hold the fuel rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to operate.

The amount of fuel purchased is determined by the design of the fuel and by the expected generation during the life of the fuel. Nuclear fuel capital expenditures were developed on the basis that Fermi 2 transitioned from its 18-month operating cycle to the 24-month operating cycle following RF21 in winter/spring of 2022, which occurred.

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The accounting of nuclear fuel expenditures completes with the delivery of the fabricated nuclear fuel to the Fermi 2 Power Plant. Expenditures arising from on-site activities such as new fuel receipt, new fuel storage and insertion of the new nuclear fuel into the reactor core are recorded in the appropriate expense account.

Q79. Can you explain the Total Nuclear Fuel expenditures as shown on Exhibit A-12, Schedule B5.3, page 1, line 10?

A79. Yes. The Total Nuclear Fuel capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.3 million, \$112.0 million and \$135.1 million respectively and are consistent with Fermi 2's projections in the Company's 2024 PSCR Plan in Case No. U-21425.

Q80. Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?

A80. Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2 operates on a 24-month fuel cycle and fuel expenditures occur at relatively fixed points in time relative to that 24-month fuel cycle (most nuclear fuel capital expenditures occur approximately six months prior to a refueling outage); therefore, Total Nuclear Fuel capital expenditures can be expected to vary each year but follow a repeating two-year pattern.

Q81. How would you characterize the level of expenditures for Fermi 2's Total Nuclear Fuel?

A81. Fermi 2's fuel expenditures are reasonable and prudent. I expect fuel expenditures to continue to be reasonable as the Company has secured the necessary uranium, conversion, enrichment and fabrication through the projected test period ending December 31, 2025.

AFUDC Forecast

Q82. Can you explain the Allowance for Funds Used During Construction (AFUDC) as shown in Exhibit A-12, Schedule B5.3, page 5?

A82. Nuclear Generation capital expenditures include an Allowance for Funds Used During Construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP); eligible projects are those projects greater than $50,000 and lasting more than six months. The actual historical period Total AFUDC – Nuclear Production Plant was $10.8 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 33, column (b). The forecasted Total AFUDC – Nuclear Production Plant for the projected test period is $13.1 million as shown in Exhibit A-12, Schedule B5.3, page 5, line 33, column (c).

Q83. How did you forecast the AFUDC as shown in Exhibit A-12, Schedule B5.3, page 5?

A83. The Nuclear Production Plant – Routine Expenditures AFUDC forecast uses a historical trend to estimate AFUDC as the mix of eligible projects is fairly consistent year-to-year. The Nuclear Production Plant – Project Specific AFUDC forecast explicitly calculates AFUDC for eligible projects using project-specific CWIP balances multiplied by the AFUDC rate where the AFUDC rate is the authorized cost of capital rate of 5.561% consistent with the December 1, 2023 Order in Case No. U-21297.

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Removal Costs, Plant in Service and CWIP Forecast

Q84. What is provided on the schedule entitled Removal Costs, Plant in Service and CWIP schedule on Exhibit A-12, Schedule B5.3, page 6?

A84. This schedule provides a breakdown of plant activities which are used by Witness Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the projected balance sheet.

Capital expenditures consistent with page 1 are summarized in columns (c) through (f). Routine and Non-Routine projects are sub-totaled on Lines 1 and 31 respectively, while Fermi 2 License Renewal has been identified separately on line 33 because this is recorded to Plant Held for Future Use. Column (b) includes a corresponding in-service assumption: "Annual" is indicated for both routine and non-routine spend because these projects are generally unitized within the year of spend.

Column (g) includes an estimated percentage of removal costs that are included within the capital expenditures. Removal costs, as discussed by Witness Uzenski, are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore not depreciable. Removal cost of 15% based on historical trend of removals as a component of capital expenditures is applied to Routine and Non-Routine project expenditures.

Column (h) through (j) reflect calculated removal costs based on projected Capital Expenditures in columns (d) through (f) multiplied by the removal cost percentage in column (g). The remaining Capital Expenditures will appear in Plant in Service columns (k) through (m) since the in-service assumption is "Annual." The CWIP columns (n) through (p) show CWIP activity.

<u>2022 – 2025 Capital Projects Summary</u>

Q85. What is your opinion regarding the reasonableness of the forecasted capital expenditures for Nuclear Generation?

A85. I believe the forecasted capital expenditures for Nuclear Generation are reasonable and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule B5.3, page 1, accurately represents the capital expenditures that can reasonably be expected to continue operation of nuclear assets of similar age and vintage. My summation of projects reflects DTE Electric's commitment to ensure the safe and reliable operation of Fermi 2 through its current operating license expiration in 2045. As I have expressed previously, these capital expenditures are prudent and reasonable given the regulations, goals and conditions under which Fermi 2 operates.

<u>Nuclear Generation O&M Expense</u>

Q86. Can you provide an outline of your Nuclear Generation O&M discussion?

A86. Yes. My testimony will begin with the O&M Expenses Overview and then discuss and support the additional details regarding:

- Rate Case Adjustments
- Adjusted Historical Test Period
- Projected Adjustments

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O&M Expenses Overview

Q87. Can you provide an overview of the Nuclear Generation O&M expenses supported by your testimony?

A87. Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M expenses for the 12-month historical test period ended December 31, 2022, adjustments to the historical test period, and then the forecasted O&M expenses for the 12-month projected test period ending December 31, 2025.

The actual O&M expenses by FERC account for the 12-month historical test period ended December 31, 2022 were $220.3 million as shown in column (c). Rate case adjustments are made in column (d) to reduce O&M by $28.6 million to account for the Nuclear Surcharge, in column (e) to reclassify Project Evaluation Review Committee (PERC) nuclear O&M project expenditures, and zero other historical adjustment in column (f). These rate case adjustments result in $191.8 million of adjusted O&M for the 2022 historical test period as shown in column (g).

Projected adjustments of $5.1 million, $4.8 million and $4.9 million in columns (h), (i) and (j) respectively account for inflation. The $35.9 million decrease in column (k) is subtracted to account for outage accrual adjustments and O&M is reduced by $11.4 million in column (l) to account for the total PERC expense in the forecasted test period as supported by calculations performed by Company Witness Uzenski. These projected adjustments yield a total change of $32.4 million as shown in column (m).

With the above adjustments, the forecasted O&M expenses for the 12-month projected test period are $159.4 million as shown in column (n).

Q88. What projected Total Nuclear Power Generation O&M expenses are you supporting?

A88. I am supporting projected Total Nuclear Power Generation O&M expenses of $159.4 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (n) as reasonable and prudent.

Rate Case Adjustments

Q89. Can you explain the basis for the Rate Case Adjustments in column (d) of Exhibit A-13, Schedule C5.3, page 1?

A89. Site security and radiation protection costs were removed from base rates and recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-14399. The Nuclear Surcharge reduction of $28.6 million as summed on line 24, column (d) accomplishes this requirement. The complete elimination of all financial statement impacts of the Nuclear Surcharge are supported by Witness Uzenski.

Q90. Can you explain the basis for the Rate Case Adjustments in column (e) of Exhibit A-13, Schedule C5.3, page 1?

A90. The Reclassify PERC adjustment nets to zero as shown on line 24, column (e). This reclassification is performed to make explicit the $15.0 million PERC Base Expense shown on line 21, column (e) and the $16.3 million of PERC Regulatory Asset amortization shown on line 22, column (e) are not inflated in the projected adjustments. I will explain the PERC Regulatory Asset mechanism later in my testimony.

Adjusted Historical Test Period

Q91. Can you explain the components that constitute the actual Total Nuclear Power Generation O&M expenses for adjusted historical test period in line 24, column (g) of Exhibit A-13, Schedule C5.3, page 1?

A91. Total Nuclear Generation O&M of $191.8 million consists of the Nuclear Organization, PERC Base Expense, amortization of the PERC Regulatory Asset, regulatory assessments and dues, and refueling outage expenses. I detail these expenses for the 2022 historical period on page 2 of Exhibit A-13, Schedule C5.3.

Q92. What is the need for and basis of the "Nuclear Organization" expenses that are included in the 2022 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 1?

A92. Nuclear Organization expenses are the baseline employee, services and material expenses required to safely and reliably operate Fermi 2. The Nuclear Organization expenses for the historical test period ended December 31, 2022 were $94.3 million.

Q93. What is the need for and basis for the "PERC Base Expense" expenses that are included in the 2022 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 2?

A93. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 approved an annual base level of PERC expenses of $4.9 million for nuclear O&M projects and the Commission Order in Case No. U-20561 increased

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the approved annual base level of PERC expenses to $15.0 million; the PERC Base Expense of $15.0 million depicted on line 2 recognizes those approvals.

Q94. What is the need for and basis for the "Reg Asset Amortization - PERC" expenses that are included in the 2022 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?

A94. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 approved a regulatory asset for annual PERC projects O&M expenditures that exceed the annual base level of PERC expenses of $4.9 million for nuclear O&M projects. In Case No. U-20561, the Commission Order updated the approved regulatory asset for annual PERC projects O&M expenditures that exceed the annual base level of PERC expenses of $15.0 million for nuclear O&M projects. The Order in Case No. U-18014 established the amortization period of this regulatory asset as five years. Consistent with that Order, the $16.3 million depicted on line 3 is the amount of the PERC Regulatory Asset amortized in 2022.

Q95. What is the need for and basis for the "Regulatory Assessments and Dues" expenses that are included in the 2022 historic period for Operation and Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 4?

A95. A majority of these assessments and dues are regulatory driven, such as those assessments and dues required by the NRC to cover oversight of the plant. In addition, assessments and dues are associated with licensing requirements including the Emergency Response Organization (ERO) and various industry groups.

Industry groups include the Institute of Nuclear Power Operations (INPO), which assists utilities in operating nuclear plants to the highest safety standards, the Nuclear Energy Institute (NEI), which assists in common issues impacting the nuclear industry, as well as the Electric Power Research Institute (EPRI) and the General Electric Boiling Water Reactor Owners' Group, both of which sponsor research that is used by nuclear plants to operate more safely and economically.

The ERO supports the Fermi 2 Emergency Plan which is a license requirement necessary to ensure the health and safety of the public during emergency response events. The ERO funds federal, state and local county emergency facilities in support of the Fermi 2 Emergency Plan.

Q96. Which assessments and dues are non-discretionary (i.e. mandated)?

A96. NRC, INPO and ERO assessments and dues are non-discretionary.

Q97. Why does the Company pay the discretionary assessments and dues?

A97. Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and operators in helping to shape important industry issues and regulation through a coordinated and solidified approach. The nuclear industry clearly recognizes that any one plant can abruptly upset the entire industry due to performance issues. As a result, this industry believes in significant group participation and knowledge sharing to help preclude such an event.

Q98. What are some specific benefits that EPRI provides DTE Electric and contributes to the safe, reliable, and economic operation of the Fermi 2 Power Plant?

A98. EPRI provides DTE Electric with the benefit of access to state-of-the-art industry research in the functional areas such as nuclear fuel reliability, reactor vessel and internals aging management, value-based maintenance, training, nuclear risk and safety management, and radiation safety.

To further provide an example of a specific benefit, EPRI membership is an integral part of DTE Electric's (and indeed the nuclear industry's) probabilistic risk assessment (PSA) program. The PSA engineer qualification at Fermi 2 requires learning the EPRI PSA courses and PSA tools used by DTE Electric such as MAAP 5, GOTHIC and PHOENIX, which are all developed and supported by EPRI. Without EPRI membership, DTE Electric would have to develop duplicative PSA education courses and PSA tools which would not be reasonable nor prudent.

Q99. What are some specific benefits that NEI provides DTE Electric and contributes to the safe, reliable, and economic operation of the Fermi 2 Power Plant?

A99. NEI provides DTE Electric (as an NEI member) access to its Personnel Access Database System (PADS). NEI membership is required to access PADS. PADS is a database maintained and administered by NEI and contains information provided by

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PADS participants concerning individuals who request access to a commercial nuclear facility; this information includes dates that an individual was granted or denied access, an individual's training and radiological dosage records. NRC regulations do not require the use of PADS but PADS does offer an efficient method for commercial nuclear plant licensees to comply with NRC regulations at 10 CFR 73.56 and to share information about individuals who were denied access or have had their access terminated per NRC regulations. Without access to PADS, DTE Electric would have to create a duplicative system of verifying an individual's plant access history – which would not be reasonable nor prudent.

NEI also provides DTE Electric with resources known as the Composite Adversary Force (CAF) to support NEI Force-on-Force security inspections. NEI membership is required to use the CAF. Since 2004, the NRC has relied on the NEI CAF to provide a credible, well-trained and consistent mock adversary in Force-on-Force inspections; Force-on-Force inspections assess a nuclear power plant's physical protection measures to defend against a "design-basis treat." To avoid conflicts of interest, the NRC requires a clear separation of functions between the mock adversary and the plant security forces. NRC regulations do not require the use of the NEI CAF but the NEI CAF does provide NEI members with an efficient means for commercial nuclear licensees to conduct NRC Force-on-Force inspections. Without NEI CAF, DTE Electric would be required to establish a duplicative mock adversary force using independent mock adversaries that met NRC standards – which would not be reasonable nor prudent.

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Q100. How does NEI support safer nuclear operations through collective nuclear industry action?

A100. NEI has supported a collective industry response to the events concerning the Fukushima Dai-ichi – in particular, NEI led the nuclear industry's adoption of the Diverse and Flexible Coping Strategies (FLEX) which increases each plant's defense-in-depth for beyond-design-basis scenarios. NEI has also led industry efforts to strengthen cybersecurity regulations. Certainly, these initiatives to make nuclear generators safer are in the best interests of our communities and DTE Electric's association with NEI is reasonable and prudent.

Q101. Does DTE Electric use other discretionary memberships to benefit our customers and the communities the Company serves?

A101. Yes. An example of another discretionary membership is NUPIC (Nuclear Procurement Issues Corporation) which is a cooperative program for performing and sharing audits of suppliers providing DTE Electric (and the nuclear industry) nuclear-quality parts. NRC regulations (*generally*, Appendix B to Part 50) require NRC licensees such as DTE Electric to audit its suppliers of nuclear-quality parts and maintain an Approved Suppliers List (ASL) – the number of such suppliers is quite large, so NUPIC allows members to use the audits of other members to maintain the suppliers on each licensee's ASL. Without NUPIC, DTE Electric would be required to audit every supplier listed on its ASL by itself which would not be reasonable nor prudent.

Q102. What is the need for and basis for "Total Refueling Outage" expenses for the 2022 historical period on Exhibit A-13, Schedule C5.3, page 2, line 10?

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A102. As discussed earlier in my testimony, the Fermi 2 plant operates on an 24-month refueling cycle such that every 24 months Fermi 2 would shut down to refuel the reactor. The "Total Refueling Outage" expenses are those costs necessary to (1) refuel the Fermi 2 reactor and (2) perform offline maintenance to ensure Fermi 2 can operate safely and reliably for the next operating cycle.

The "Total Refueling Outage" expense consists of the actual refueling outage costs (line 7), the refueling outage accrual (line 8) and the refueling outage accrual reversals (line 9) for the 2022 historical period. Line 10 nets these three components and represents an accounting practice of levelizing incremental refueling expenses by accruing the anticipated refueling expenses over the term of an operating cycle.

Q103. Why does DTE Electric levelize its incremental refueling outage expenses?

A103. DTE Electric levelizes its incremental refueling outage expenses so that the difference in expense between outage and non-outage years does not burden DTE Electric customers with large rate fluctuations or create financial swings for the Company. For example, if the Company bases the rate request on the projections for a refueling outage year and all the expenses of that outage appear in that year's projections, then the Company would be presenting an unnecessarily high cost of providing Fermi 2 generation over the period the rates are in effect. The inverse is also true if the Company used a non-refueling outage year projection for the same purpose. This is consistent with the treatment in prior cases where the Commission has allowed levelized refueling outage expenses in setting rates.

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Q104. What is the basis for the "Refuel Outage" expense at $73.1 million for the 2022 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?

A104. This is the actual refuel outage expenditures incurred in the 2022 historical period for RF21.

Q105. How does DTE Electric manage incremental refueling outage expenses?

A105. The Company manages incremental expenses through structured planning and preparation that is consistent with industry standards and processes. We implemented rigorous financial controls that supported daily management of resources during the execution phase of the refueling outage. This management of resources includes daily reviews of scope completion, schedule and budget. As work completes, contracted resources exit promptly from the site to ensure that costs are controlled.

Q106. What is the basis for the "Refuel Outage Accrual" expenses at $18.4 million for the 2022 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 8?

A106. This is the actual amount accrued in the historical period for RF21 and RF22.

Q107. How does DTE Electric determine the value of the Refuel Outage Accrual?

A107. As the purpose of the Refuel Outage Accrual is to levelize the costs of refueling outages over the appropriate time horizon, DTE Electric developed a model outage template that defines a routine baseline refueling outage in terms of timing, and incremental O&M expenditures for labor, services, materials and other outage costs. It is important to note that the Refuel Outage Accrual is for those incremental O&M

costs associated with a refueling outage; routine expenses such as DTE Electric Nuclear Generation strait-time labor, structural overtime and year-round supplier services that are incurred regardless of the outage are "Nuclear Organization."

As I will discuss later in my testimony, incremental outage costs that are generally not associated with the baseline outage activities or cause significant variation in outage costs from outage-to-outage are assigned to PERC O&M.

Q108. What is the basis for the "Refuel Outage Reversal" of $38.0 million for the 2022 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 9?

A108. This is the actual amount of outage accrual that had been accrued in advance for RF21 and credited to O&M in the historical test period.

Projected Adjustments

Q109. Can you explain the basis for the inflation adjustments in columns (h), (i) and (j) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A109. The labor and material prorated inflation adjustment rates of 3.2% for 2023, 2.9% for 2024 and 2.9% for 2025 are supported by the testimony of Witness Uzenski. Nuclear Generation applied these forecasted inflation rates to the adjusted historical test period costs in column (g).

Q110. Can you explain the basis for the Outage Accrual adjustment in column (k) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A110. The Outage Accrual adjustment is to normalize the outage accrual for the projected test period to approximately $22.5 million. This Outage Accrual adjustment reflects

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our commitment to improving refueling outage performance and reducing future outage O&M expenditures.

Q111. What duration have you projected for RF22?

A111. The 2024 PSCR Plan (Case No. U-21425) projected an outage duration of 45 days for RF22 (projected for spring 2024).

Q112. Can you explain the basis for the PERC Amortization adjustment in column (l) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

A112. As explained and supported by Witness Uzenski, the Commission Order in Case No. U-18014 not only approved an annual base level of PERC expenses for nuclear O&M projects, but also provided deferral and amortization treatment for any expenses over or under the base amount. The PERC Base expense was changed by $10.1 million from $4.9 million per year to $15.0 million per year in the May 8, 2020 Order in Case No. U-20561.

The PERC Amortization reduction of $11.4 million in column (1) on line 24 consists of the $0.0 million change in the approved annual PERC Base Expense as shown in column (l) on line 21 and a forecasted reduction of $11.4 million in the amortization of the PERC Regulatory Asset as shown in column (l) on line 22.

The Total PERC Expense for the projected test period is forecasted at $19.9 million as shown in column (n) on line 23. The derivation of this Total PERC Expense is shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness Uzenski; I detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in Exhibit A-13, Schedule C5.16, page 1.

Q113. Can you explain the Total PERC O&M Expenditures detailed in Exhibit A-13, Schedule C5.16, page 1?

A113. This exhibit shows the by-project PERC O&M expenditures for the 2022 historical period and projected Calendar Years 2023, 2024, and 2025 planned expenditures totaling $18.1 million, $8.9 million, $22.6 million and $8.6 million respectively.

Q114. Can you explain how DTE Electric determines which projects are included in PERC O&M as detailed in Exhibit A-13. Schedule C5.16, page 1?

A114. Exhibit A-13, Schedule C5.16 is the updated list of PERC O&M projects. DTE Electric has provided similar updated exhibits in each of the past rate cases since Case U-18014 established the PERC O&M regulatory asset construct. PERC O&M projects expenditures are those incremental expenditures associated with Nuclear Generation O&M projects. I will provide a rationale for select project's inclusion in the PERC O&M later in my testimony.

Q115. How do the Total PERC O&M Expenditures on line 30 of Exhibit A-13, Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?

A115. As an example, the projected total PERC O&M expenditures of approximately $8.9 million for Calendar Year 2023 shown in Exhibit A-13, Schedule C5.16, page 1, line 30, column (c) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column (d).

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Q116. How does the PERC amortization expense on line 15 of Exhibit A-13, Schedule C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?

A116. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule C5.17, page 1, line 15, column (g) shows $4.9 million as the calculated amortized portion of PERC O&M for the 12-month projected test period ending December 31, 2025. This $4.9 million is used in Exhibit A-13, Schedule C5.3, page 1, line 22, column (n).

Q117. What was the rationale for the Refueling Outage Planning, Readiness and Demobilization project shown on line 1 of Schedule A-13, Schedule C5.16, page 1?

A117. As I discussed earlier in my direct testimony, DTE Electric begins planning for the upcoming refueling outage at approximately T-24 months prior to the refueling outage. Expenditures for refueling outage planning, scheduling and readiness follow a 24-month pattern and as such, do not lend themselves to a levelized expenditure schedule; the amount of expenditures can also vary from outage-to-outage depending on refueling outage scope. Planning activities include work package planning, work order reviews and resource planning; scheduling includes work plan integration and resource levelization efforts; readiness includes physical tasks such as staging parts, building some scaffolding that can be done prior to the refueling outage, readying temporary power carts, and setting up temporary infrastructure needs such as additional computers and housing trailers. The Refuel Outage Planning line item was included in the original PERC O&M discussion in Case No.

U-18014 and has been updated accordingly with each subsequent DTE Electric rate case.

Q118. What was the rationale for the Desludge - Torus project shown on line 2 of Schedule A-13, Schedule C5.16, page 1?

A118. The torus is a water-filled donut-shaped containment structure designed to absorb excess thermal energy and provide emergency water to the reactor core during a postulated accident scenario. Each refueling outage specially-qualified divers de-sludge the torus to minimize the amount of debris within the torus; this debris normally accumulates over the course of the operating cycle. Once the torus has been de-sludged the divers inspect and repair the submerged coatings of the torus containment structure; the divers also inspect and replace pump suction strainers. The Desludge – Torus project was first included in the PERC O&M exhibit in Case No. U-20162 and has had updated project expenditures included in subsequent rate case PERC O&M exhibits.

Q119. What was the rationale for the Reactor Feed Pump Turbine (RFPT) Inspections project shown on line 3 of Schedule A-13, Schedule C5.16, page 1?

A119. The Reactor Feed Pump Turbines (RFPTs) require a full tear-down inspection approximately every ten years to satisfy loss control criteria. Fermi 2 has two RFPTs (North and South). Each RFPT drives one Reactor Feed Pump (RFP) which in turn supplies the driving force for reactor feedwater. DTE Electric completed the inspection of the South RFPT in RF21 (2022) and projects to complete the North RFPT inspection in RF22 (2024). The RFPT inspections were first included with

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the Case No. U-20836 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q120. What was the rationale for the Residual Heat Removal Heat Exchanger (RHR HX) coating project shown on line 4 of Schedule A-13, Schedule C5.16, page 1?

A120. A requirement for the renewed Fermi 2 operating license is to perform inspections of internal coatings of certain piping, piping components, heat exchangers and tanks where the loss of the coating or lining could impact the ability of that equipment to perform its function during the Fermi 2 Period of Extended Operations; the Fermi 2 Residual Heat Removal Heat Exchangers (RHR HX) have such internal coatings. Fermi 2 has two RHR HXs ('A' and 'B'), both of which are nuclear-safety equipment. Each RHR HX supports an independent and redundant division of nuclear-safety equipment where the RHR HX transfers residual heat away from the nuclear systems and to the Fermi 2 Ultimate Heat Sink during certain accident scenarios. Previous inspections of the original RHR HX coatings had shown evidence of degradation; therefore, to ensure the RHR HX coatings would support safe operations through 2045 DTE Electric is replacing the internal coatings of the RHR HXs. DTE Electric completed the coating replacement of the RHR HX A in RF21 and projects to complete the replacement of the RHR HX B coating in RF22. The RHR HX coating replacements project was first included with the Case No. U-20836 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

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Q121. What was the rationale for the Hydraulic Control Unit (HCU) preventative maintenance project shown on line 5 of Schedule A-13, Schedule C5.16, page 1?

A121. The Fermi 2 Hydraulic Control Units (HCUs) require a one-time preventative maintenance (replacement of internal soft components such as diaphragms and gaskets, filters as well as directional control valves) to ensure safe operations through 2045. Fermi 2 has 185 HCUs – one for each control rod drive mechanism (CRDM). The HCU controls hydraulics to the CRDM. DTE Electric has levelized the HCU preventative maintenance over several outages and completed preventative maintenance activities on 37 HCUs in RF21 and projects to complete preventative maintenance activities on 34 HCUs in RF22. The HCU preventative maintenance project was first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q122. What was the rationale for the Force-on-Force inspections (FOF) shown on line 6 of Schedule A-13, Schedule C5.16, page 1?

A122. Force-on-Force (FOF) inspections are NRC inspections and exercises that assess the ability a nuclear licensee such as DTE Electric to defend a nuclear power plant from a design-basis-threat. The NRC FOF includes a mock adversary force (MAF) that simulates hostile actions against the plant's security personnel and systems. These NRC FOF inspections occur approximately every three years. The NRC last performed a FOF at Fermi 2 in 2022 and DTE Electric projects the next NRC FOF in 2025. The FOF inspections were first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q123. What was the rationale for the Integrated Leak Rate Test (IRLT) shown on line 7 of Schedule A-13, Schedule C5.16, page 1?

A123. The Integrated Leak Rate Test (ILRT) is an NRC-required evolution to confirm the plant's primary containment system is performing its function (*generally*, Appendix J for Part 50). A licensee such as DTE Electric must perform the ILRT at least once every 15 years – the NRC transitioned to this longer periodicity in 2012 based on research performed by EPRI and surveys conducted by NEI (previously an ILRT was required at least once every ten years), saving the Company (and thus customers) time and money. DTE Electric successfully completed the Fermi 2 IRLT in RF21. The Fermi 2 ILRT was first included with the Case No. U-20836 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q124. What was the rationale for the High Energy Line Break (HELB) analysis shown on line 8 of Schedule A-13, Schedule C5.16, page 1?

A124. Fermi 2 Power Plant is maintained and operated per its NRC license. Supporting the Fermi 2 license are many technical specifications, designs, configuration controls and design calculations. One such design calculation affects environmental (temperature, humidity, pressure) conditions that can be assumed during plant operating scenarios such as a high energy line break (HELB). The HELB analysis updates the Fermi 2 environmental calculations using modern models such as the EPRI GOTHIC which in turn allows DTE Electric to reevaluate and provide additional margin to certain Fermi 2 technical specifications and reduce the likelihood of an unplanned limited condition of operation.

Q125. What was the rationale for the Independent Spent Fuel Storage Installation (ISFSI) and ISFSI fuel characterization shown on lines 28 and 13 of Schedule A-13, Schedule C5.16, page 1?

A125. Fermi 2 ISFSI campaigns remove spent nuclear fuel assemblies from the Fermi 2 spent nuclear fuel pool, load the spent nuclear fuel assemblies into NRC-licensed dry casks, and then transport the dry casks to their interim storage location at the Fermi 2 ISFSI Pad. Prior to loading the spent nuclear fuel assemblies into the casks, DTE Electric must characterize the spent nuclear fuel to ensure the spent nuclear fuel assembly remains intact and that its composition is as expected to ensure the spent nuclear fuel loaded into each cask is consistent with the dry cask license. The 2023 ISFSI campaign included 10 dry casks and transitioned 680 spent nuclear fuel assemblies from the Fermi 2 spent fuel pool to the Fermi 2 ISFSI Pad. The ISFSI-related expenditures were first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q126. What was the rationale for the Spent Fuel Pool (SFP) cleanup campaign shown on line 14 of Schedule A-13, Schedule C5.16, page 1?

A126. The Fermi 2 Spent Fuel Pool (SFP) is a small, water-filled pool adjacent to the reactor and is used to store spent nuclear fuel, incoming new nuclear fuel, control rod blades (CRBs) and nuclear instrumentation equipment such as dry tubes and local power range monitors (LPRMs). While ISFSI campaigns transition spent nuclear fuel from the SFP to dry-cask storage, the SFP storage locations for CRBs and nuclear instrumentation equipment are also finite and periodically DTE Electric must dispose of this depleted equipment to clear space for the CRB/SRM/IRM removals projected in upcoming refueling outages. DTE Electric removed and disposed 28 CRBs and 7 dry tubes and 3 LPRMs from the SFP. The SFP cleanup campaigns were first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits. DTE Electric projects the next SFP campaign to occur around the year 2030.

Q127. What was the rationale for the Core Shroud Inspections shown on line 17 of Schedule A-13, Schedule C5.16, page 1?

A127. The core shroud is a cylindrical shroud that directs coolant flow through the core and helps maintain fuel alignment to ensure control rods can be inserted into the core. DTE Electric performs core shroud inspections approximately every ten years to monitor the integrity of the core shroud per EPRI guidelines endorsed by the NRC; however, with Fermi 2's transition to the 24-month cycle, DTE Electric was required to perform the core shroud inspections one outage year earlier than otherwise required. DTE Electric projects to perform the core shroud inspections in RF22. DTE Electric last performed the core shroud inspection in RF18 (2017) which was depicted in the Case No. U-20162 PERC O&M exhibit.

Q128. What was the rationale for the License Renewal Inspections shown on line 27 of Schedule A-13, Schedule C5.16, page 1?

A128. Once Fermi 2 transitions to its Period of Extended Operations in 2025, the capital project License Renewal Implementation will complete and be in service. There will be ongoing incremental inspections required as a part of the Fermi 2 renewed license which DTE Electric will account for in the License Renewal Inspection project. The

License Renewal Inspection project was included in the Case No. U-21297 PERC O&M Exhibit.

Q129. What was the rationale for the Feed Water Heater (FWH) Bridging Strategy project analysis shown on line 20 of Schedule A-13, Schedule C5.16, page 1?

A129. I have discussed the technical importance of the FWHs in the capital discussion. Emergent repairs to the #3S FWH were performed in RF20. DTE Electric performed inspections of these six FWHs in RF21 to support safe, reliable operation until RF22. DTE Electric is projecting to perform inspections and repairs to the #3S, #3N, #4S, #4N, #5S and #5N FWHs to support reliable operation until these six FWHs are replaced in RF23 and RF24. This proceeding is the first inclusion of the FWH Bridging Strategy expenditures as PERC O&M.

Q130. What was the rationale for the Circulating Water Pump (CWP) refurbishments shown on line 21 of Schedule A-13, Schedule C5.16, page 1?

A130. The Fermi 2 Circulating Water Pumps (CWP) and motors require refurbishment approximately every 10 years to ensure reliable operation. Fermi 2 Power Plant has five CWPs, each driven by a 5000-horsepower motor, that supply the driving force for the Fermi 2 Circulating Water System. In general, Fermi 2 Power Plant only requires four of the five CWPs to be at full-power operations during the cooler months of October – April. It's during this time that DTE Electric can remove a CWP from service, ship the pump and motor offsite for refurbishment, and then reinstall the pump and motor prior to the warmer months when all five CWPs are required for full-power operations. The CWP refurbishments were first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q131. What was the rationale for the High Pressure Turbine (HPT) inspection shown on line 25 of Schedule A-13, Schedule C5.16, page 1?

A131. The High Pressure Turbine (HPT) requires a full tear-down inspection approximately every 120,000 hours of operation to satisfy loss control criteria. The Fermi 2 main turbine system consists of a high pressure element (the HPT) in tandem with three low-pressure elements (low-pressure turbines (LPTs)). DTE Electric projects to complete the HPT inspection in RF23 (2026). The HPT inspections were first included with the Case No. U-20162 PERC O&M Exhibit and has had updated project expenditures with subsequent rate case PERC O&M exhibits.

Q132. What was the rationale for the 24-Month Operating Cycle project shown on line 11 of A-13, Schedule C5.16, page 1?

A132. The 24-month operating cycle project reduces the frequency of Fermi 2 refueling outages and improves operating time. Operating on a 24-month cycle results in three refueling outages every six years; operating on an 18-month operating cycle results in four refueling outages every six years. Prior to the 24-month operating cycle project, Fermi 2 previously operated with 18-month operating cycles; therefore, transitioning to a 24-month operating cycle results in additional generation over a six-year cycle due to fewer refueling outages.

Fermi 2's cycle length is limited by our NRC license. The 24-Month Operating Cycle project performed an analysis to ensure the plant could operate 24 months between refueling outages and submitted that analysis as a license amendment request to the NRC to update the Fermi 2 license to allow a 24-month cycle. DTE Electric received NRC approval in early 2021 and began its first 24-month operating cycle in 2022 upon exiting RF21.

The Company first introduced the 24-Month Operating Cycle project in Case No. U-20162. The Commission responded favorably and approved cost recovery associated with the 24-Month Operating Cycle project in the Case No. U-20162 Order dated May 2, 2019.

Q133. What are the Total Nuclear Power Generation O&M expenses that you support for the projected test period ending December 31, 2025?

A133. I support Total Nuclear Power Generation O&M expenses of $159.4 million for the projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line 24, column (n). As I have discussed previously, these projected Total Operation and Maintenance expenses are required for the safe and reliable operation of Fermi 2 for the projected test period. I consider these expenses to be prudent and reasonable.

<u>Nuclear Surcharge</u>

Q134. Is the Company requesting a change to the Nuclear Surcharge?

A134. Only with respect to inflation for the Site Security and Radiation Protection portion of the Nuclear Surcharge. The Company is proposing an updated Nuclear Surcharge based on the same approach approved by the Commission in Case Nos. U-17767, U-18014, U-18255, U-20162, U-20561, U-20836 and U-21297 and depicted in Exhibit A-20, Schedule J1.

The Site Security and Radiation Protection portion of the surcharge has been updated to reflect 2022 historical expense adjusted for inflation on line 2. The inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.

The Nuclear Decommissioning Funding portion of the surcharge shown on line 3 is unchanged.

The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual surcharge shown on line 4 is unchanged.

The resulting nuclear surcharge set forth in Company rates is supported by Company Witness Willis on Exhibit A-16, Schedule F6.

Q135. What is the Nuclear Surcharge that you support for the 12-month projected test period ending December 31, 2025?

A135. I support the Proposed Nuclear Surcharge of $40.1 million for the projected test period as shown in Exhibit A-20, Schedule J1, page 1, line 5, column (b); this represents a change of approximately $1.2 million from the current authorized Nuclear Surcharge shown on line 6, column (b). The Proposed Nuclear Surcharge funds Fermi 2 site security, radiation protection, nuclear decommissioning and the disposal of LLRW; these activities are required for safe and secure operation of the

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Fermi 2 Power Plant for the projected test period. I consider the Proposed Nuclear Surcharge to be prudent and reasonable.

Q136. Does this complete your direct testimony?

A136. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SATVIR S. DEOL

Q1. What is your name, business address and by whom are you employed?

A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Electrical Engineering specializing in Power Distribution from Michigan Technological University. I graduated from the University of Minnesota with a Master of Science in Electrical Engineering specializing in Power System Control. I also have a Master of Business Administration specializing in Finance from University of Michigan, Dearborn. Furthermore, I have attended professional development courses in power system design & protection and circuit modeling & power flow analysis. I was also trained in the Toyota Production System (TPS) continuous improvement methodologies.

Q4. Please summarize your professional experience.

A4. I worked for Shell Western Exploration & Production, Inc. (SWEPI) as a facilities engineer from 1990 to 1992. I was responsible for coordinating & performing maintenance on substations, co-generation facilities, and the power distribution network for all oil production fields and offshore platforms in California. I also supported the field electrical teams for emergent issues and was the project manager for several major electrical projects. I worked for Ford Motor Company (Ford) from 1995 to 2007. Through my twelve-year career at Ford, I had numerous assignments with increasing responsibility. As a product design engineer, I designed electrical motors and received two patents. I have experience in the production and assembly of electrical components as a manufacturing engineer. I have worked internationally, launching an alternator rectifier assembly line in India, and upgrading a plant in Brazil. As a product planning analyst, I worked with hybrid, electrical and fuel cell vehicle architectures and gained experience working within industry consortiums. I obtained leadership experience as a powertrain capacity planning supervisor and then as an ignition system supervisor, where I had design and release responsibility of all current and future ignition systems for all North America produced V-engines. Also, I achieved my six-sigma black belt certification and led numerous continuous improvement projects.

I joined DTE Energy in 2007 as a program manager to implement continuous improvement programs within the Materials & Logistics organization. After a series of roles with increasing responsibility, in 2010 I was promoted to senior supply chain manager supporting Fossil Generation Operations.

In 2013, I moved to Distribution Operations as a program leader for a continuous improvement project focusing on the oil distribution breaker inspection process. In 2014, I assumed the role as a service center manager leading the Southwest region for Substation Operations. In this role, I was responsible for the operation, planned and corrective maintenance, and executing capital projects for substations. I was given the additional responsibility of the Southeast region in 2016. In 2018, I was promoted to director of Substation Operations.

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As director of Substation Operations, I was responsible for safe and reliable operation of all the substations within the DTE Electric service territory. The major areas of focus were: 1) safety, 2) planned maintenance, 3) emergent and corrective maintenance, 4) capital replacement programs, and 5) continuous improvement. In 2023, I assumed the role of director of Central Engineering.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. I am a Lean Six Sigma Blackbelt.

Q6. What are your current duties and responsibilities?

A6. As director of Central Engineering, I lead the Central Engineering organization that is responsible for determining the health of the Company's electric distribution assets and developing projects and programs to maintain and improve their safe, reliable, and cost-effective operation. I oversee Central Engineering activities, which include defining technical standards for the equipment to be utilized on the distribution system, long-term system planning including grid modernization, and developing major projects needed for customer connections, relocations, increasing loads, infrastructure improvements, reliability upgrades, and technology enhancements.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in the following DTE Electric cases:

U-21297 DTE Electric 2023 Rate Case

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. As referenced in witness Kryscynski's description of the Distribution Operations organization, the purpose of my testimony is to support, as reasonable and prudent, the historical capital expenditures for 2022 and projected capital expenditures for 2023 through December 31, 2025, in the distribution strategic investment category of Infrastructure Redesign and Modernization and the programs associated with the Company's Infrastructure Recovery Mechanism (IRM).

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plan (Pages 1, 2, 14-16, and 19-26)
A-23	M6	Distribution Plant Capital Project Detail – Infrastructure Redesign and Modernization
A-23	M11	Appoline Report
A-23	M13	Benefit Cost Analysis Whitepaper
A-28	R1	Buffalo Charles Letter of Support

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I Infrastructure Recovery Mechanism (IRM) Support

Part II Infrastructure Redesign and Modernization

<u>Part I Infrastructure Recovery Mechanism (IRM) Support</u>

Q12. Are any of the programs you are supporting impacted by the Company's Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM)?

A12. Yes, as described by Company Witness Foley in his testimony, in its December 1, 2023 Order in Case No. U-21297 (December 2023 Order), the Commission authorized IRM treatment for the Conversion projects (4.8kV Conversion and Consolidation (CC), 4.8kV ISO Conversion, 8.3kV CC, and City of Detroit Infrastructure (CODI)), and the Subtransmission Redesign & Rebuild program from December 1, 2023 through the end of 2025.

Q13. Is the Company proposing any additional investment in these programs during the bridge and/or test years beyond what the Commission previously authorized for recovery through the IRM?

A13. Yes, as reflected in Exhibit A-12, Schedule B5.4, the Company is proposing additional Conversions and Subtransmission Redesign & Rebuild investment during the bridge and test years of this case. Additional Conversions program investment is captured on Page 14 (Lines 28-36), Page 15 (Lines 37-56), and Page 16 (Lines 79-91). Additional Subtransmission Redesign & Rebuild program investment is captured on Page 14 (Lines 5-27) and Page 15 (Lines 66-78). This investment is incremental to the investment already authorized for IRM treatment during these years and will support different work to avoid double recovery of the same investment.

Q14. Is the Company proposing recovery for any additional investment in these programs through the IRM beyond the test year of this case?

A14. Yes, as described by Company Witness Foley, the Company is proposing a two-year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that extension the Company is proposing recovery of additional Conversions and Subtransmission Redesign & Rebuild capital investment as captured in Exhibit A-33, Schedule X1.

Part II: The Infrastructure Redesign and Modernization Pillar

Q15. Can you describe the Company's Infrastructure Redesign and Modernization Pillar?

A15. The Infrastructure Redesign and Modernization Pillar focuses on fundamentally rebuilding and modernizing the near century old grid to support the long-term grid needs. The specific investments in this pillar are essential to meeting the evolving needs of customers, including adoption of electric vehicles (EVs) and other forms of electrification, distributed energy resources (DER), and the evolving ways in which customers are interacting with the grid.

The goals of the projects and investments in this pillar are to add capacity and operational technology, while hardening the grid to enhance safety, reliability, and resiliency. These projects include elimination of loading constraints, redesign and rebuild of the subtransmission system to provide operational redundancy and address lack of capacity on significant portions of the Company's grid.

Q16. What grid investment areas are included in the Infrastructure Redesign and Modernization Pillar?

A16. Infrastructure Redesign and Modernization investments focus on the distribution and subtransmission segments of the grid.

The distribution system is designed to distribute electricity from a substation to the customers. The Company's current distribution system has voltages of 4.8 kV, 8.3 kV, and 13.2 kV. In analyzing the long-term grid needs and to address the current challenges of the 4.8 kV and 8.3 kV circuits, the Company plans to convert all 4.8 kV and 8.3 kV grid infrastructure to a higher voltage over time.

The Company's Conversion Program investments focus of converting the 4.8 kV and 8.3 kV circuits to a higher voltage. With evolving climate change, the Company is experiencing an increased number of severe weather events of greater frequency and severity. Weather impacts, aged electrical infrastructure, and the need to support current and future load growth require a higher voltage, harden, and resilient grid.

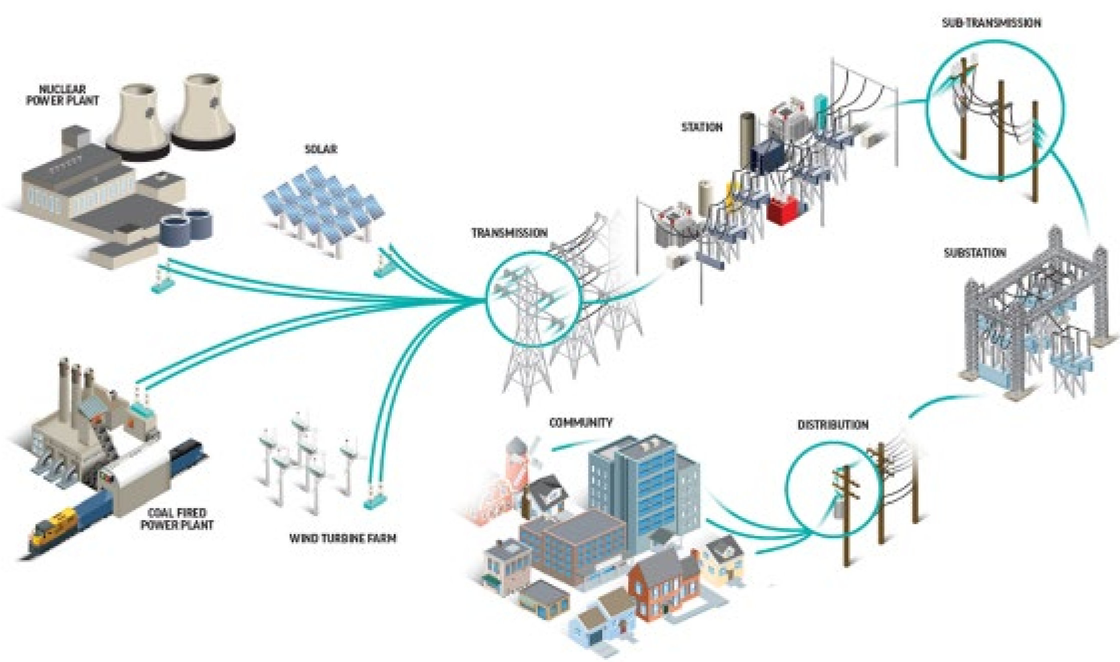
The distribution system is also addressed by the System Loading project investments. These projects focus on relieving system overloads, improving reliability, and adding capacity predominantly on the 13.2 kV distribution system.

The subtransmission system consists of the infrastructure that provides higher voltage into substations that then convert the higher voltage to lower-level distribution voltages (4.8 kV, 8.3 kV, and 13.2 kV). The Company's subtransmission system has voltages of 24 kV, 40 kV, and 120 kV.

The Company's Subtransmission Redesign & Rebuild program investments focus on this critical upstream feed to the distribution system. These projects focus on improving the reliability, redundancy, and capacity of the subtransmission system.

Figure 1 below illustrates the difference between the distribution and subtransmission system.

Figure 1 Electrical Distribution System Overview



Summary level Capital investment details for Infrastructure Redesign and Modernization projects are provided in Exhibit A-12, Schedule B5.4, pages 14-16 and Exhibit A-23, Schedule M6. Also included in Exhibit A-12, Schedule B5.4 for this category is AFUDC on page 19 and plant activity on pages 20-26, described in more detail by Company Witness Kryscynski.

Q17. Can you discuss in more detail the Infrastructure Redesign and Modernization programs?

A17. I would like to expand on these programs because I believe that will be helpful in establishing a deeper understanding of their key objectives, scope, the rationale for making the investments, and the benefits customers will receive.

- Conversion Programs
  - 4.8 kV Conversion
  - City of Detroit Infrastructure (CODI)
  - 4.8 kV ISO Conversion
  - 8.3 kV CC Pontiac Conversion
- Subtransmission Redesign & Rebuild
- Strategic Undergrounding Projects
- Primary Deconductoring
- System Loading

Conversion Programs

4.8 kV Conversion

Q18. Can you describe the Company's 4.8 kV distribution system?

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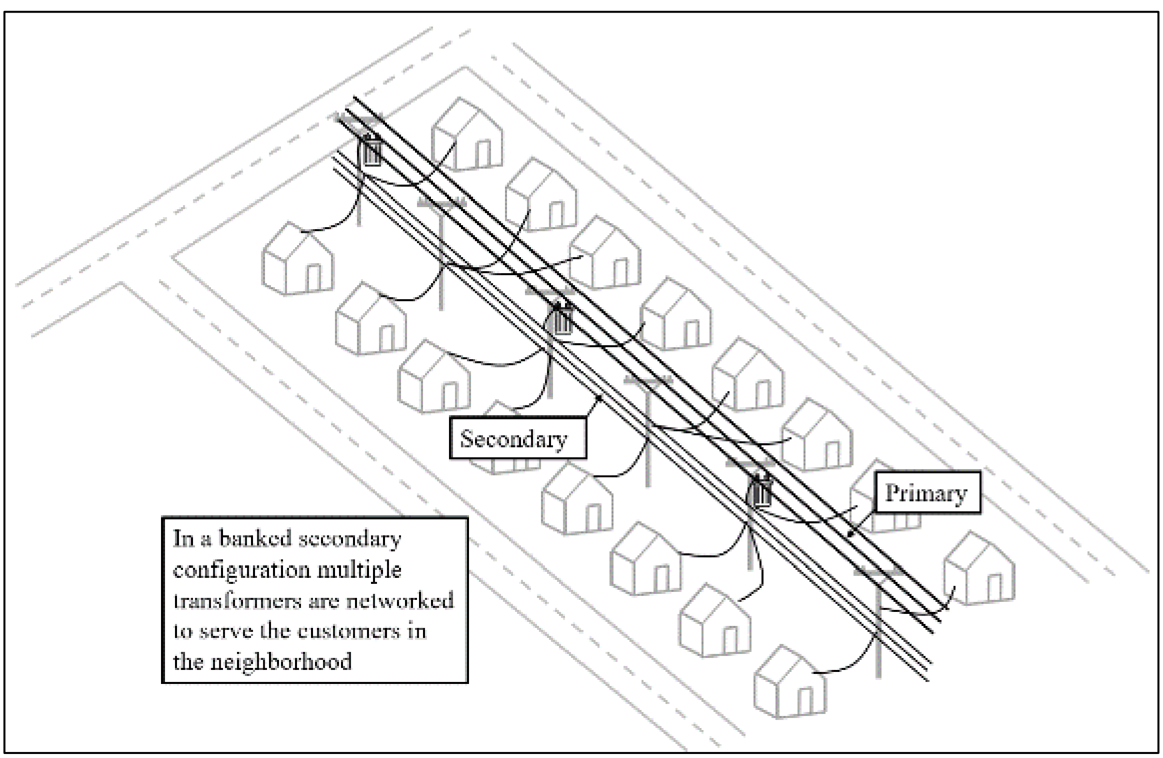
A18. The Company's original distribution system voltage is 4.8 kV. The system was designed nearly a century ago with standards of the time that included an ungrounded delta configuration with banked secondary. For an ungrounded delta configuration protective trip device to operate on the system, two of the high-power lines need to contact each other or ground. Thus, a single downed wire is challenging for the protective devices to detect in a delta configuration. A banked secondary configuration has multiple transformers interconnected to provide power to a local area of customers. Figure 2 below shows a banked secondary configuration.

Figure 2 Banked Secondary Configuration

The 4.8 kV delta configuration coupled with the banked secondary is a design from the early 1900's, which for many decades provided good reliability with a low



number of outages for the Company's customers. Currently, the 4.8 kV delta system has many challenges which include safety, reduced distribution capacity, and degrading reliability due to its age.

Q19. Can you describe in more detail the challenges and issues associated with the 4.8 kV system?

A19. Improving safety risk associated from downed wires on the current 4.8 kV ungrounded delta circuits is a major focus of the conversion program. It is more susceptible to wire-downs due to small #6 and #4 copper conductors, which are weaker in strength compared to current higher standard wires, and in many cases have deteriorated and weakened by age and the annealing effects of thermal cycling. Due to the ungrounded configuration of the 4.8kV delta system, a downed wire can potentially remain energized until mitigated by the Company's workforce.

Capacity is limited due to the inherently lower rating of equipment at 4.8 kV, including, but not limited to, substation transformers and conductor or cable sizes. On many circuits, this impacts the Company's ability to connect new customers or facilitate growth of existing customers.

Reliability of the 4.8 kV system, both in terms of outages (frequency and duration) and power quality, impacts the customer experience. When originally constructed, the 4.8kV system was modern, accessible, and reliable for a customer base with a much lower electrical demand. Driven by a combination of the age of the system, inaccessibility of infrastructure, and changing customer demands, the 4.8 kV system is no longer a reliable design choice.

In addition to the lower reliability and capacity constraints of the 4.8kV system, it also limits the operability for the Company. Smaller wire sizes and lower circuit/substation ratings limit the ability to reconfigure the system to restore customers in adjacent areas during planned or unplanned outages. This can result in larger area and longer duration outage events for the Company's customers.

Accessibility is another major challenge of the 4.8 kV system. In most neighborhoods, the 4.8 kV system was constructed as overhead rear-lot poles and wires, which customers find aesthetically preferable to front-lot construction. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Starting in the mid-1950's, many municipalities began abandoning the alleys and allowed property owners to extend their fence lines, inhibiting Company truck access to the poles and wires. Consequently, the limited access results in extended time to locate and repair trouble on the 4.8 kV system, as well as increases in time to perform tree trimming and other maintenance work.

Other key challenges impacting the Company's 4.8 kV system are:

- The 4.8 kV system can experience more significant voltage drops than higher voltage systems.
- Ringed circuit and banked secondary designs make maintenance, fault identification, troubleshooting, and restoration more difficult and therefore can result in outages that are longer in duration.

- The 4.8 kV system is less able to incorporate current technology automation standards because it has a limited amount of remote monitoring and control capability when compared to higher grid voltages. Due to inherent space limitations and equipment age, the retrofits on 4.8 kV substations to enhance remote monitoring and control capability are more costly and challenging. For example, the original 4.8 kV substation design included individual relays for individual functions, usually installed on a 3-foot-by-7-foot granite panel. When a new breaker is installed these granite panels are removed and a new prewired relay panel with current technology is installed. Even though the new prewired panel reduces installation time at the substation, all the new control wires still must be installed from the panel to the breaker, which is time consuming, and costly.

Q20. Why does the Company plan to convert its 4.8 kV system?

A20. As described earlier, the 4.8 kV system has many challenges related to safety, capacity, reliability, operability, and accessibility, and this negatively impacts the customers served by the 4.8 kV system. In analyzing the long-term grid needs and to address the current challenges of the 4.8 kV system, the Company has determined that a higher grid voltage system is required. The conversion program will build new, modern, higher voltage substations. The newly constructed higher voltage distribution circuits will be built to the current construction standards that will harden the grid and implement a higher level of automation. The conversion program will improve safety by reducing wire-down events. Converting to a higher system voltage will add capacity to support new and growing customer load, and better support new electrification technologies and DERs. The hardened circuits will improve reliability, operability, and reduce emergent maintenance costs. Automation will allow for remote operations to reduce the number of customers impacted by outages and reduce restoration time by quickly identifying trouble locations. The new circuits will be designed and built to improve accessibility by relocating to be truck accessibility wherever possible allowing for quicker crew response time.

Through the conversion program, the Company expects to see a reduction of up to 90% in customer minutes of interruption, wire downs, and trouble events.

Q21. What is the scope of the 4.8 kV Conversion program?

A21. The detailed scope of the 4.8 kV conversion program is as follows:

- Building new, higher voltage substations or in some cases expanding and upgrading existing 13.2 kV substations. This will improve the ability to connect new customers and allow for load growth for existing customers.
- Completing overhead pre-conversion work including rebuilding pole top equipment, replacing poles, wires, and transformers as needed, and installing neutral wire.
- Undergrounding of the overhead wires will also be evaluated for construction feasibility, customer acceptance, and cost effectiveness.
- Reconfiguring circuits and establishing new jumpering points will be completed to improve operability. Jumpering is used during outage circumstances and is the act of feeding a circuit that has become deenergized by connecting it to an adjacent circuit, thus restoring power to the customers on the deenergized circuit.

Line No.

- Converting and transferring the load from the 4.8 kV substations to the 13.2 kV substations.
- Installing controls and automation in the substations and circuits to current design standards.
- Remove arc wire and Detroit Public Light Department primary from the Company's system, on applicable Detroit circuits.
- Decommissioning of aging 4.8 kV substations and associated subtransmission infrastructure.

Q22. Do customers benefit from overhead pre-conversion work when it is constructed prior to building a new higher voltage substation or in parallel with substation construction?

A22. Yes. In projects where overhead pre-conversion work is performed early or in parallel with the substation construction, the customers will see the reliability benefits sooner, even though upgraded equipment will continue to operate at 4.8 kV until the area is ready for conversion. Upgraded pole-tops and wires deliver reliability improvements by a reduction in wire downs. Once the substation is subsequently built, the additional capacity benefits will be achieved as the circuits are converted to the higher voltage.

Q23. How are conversion projects prioritized?

A23. The Company's engineers develop conversion projects based on substation firm rating, circuit overloads, wire downs per OH mile, and substation risk. Consistent with other strategic projects and programs, conversion projects are prioritized using the Global Prioritization Model (GPM), which was updated in the 2023 DGP and is discussed in detail by Witness Kryscynski. A conversion project's GPM score is primarily impacted by the projects ability to address substation firm rating, circuit overloads, wire downs per OH mile, and substation risk plus the reliability improvement benefits and investments in Energy Justice (EJ) communities. More detail is provided in Exhibit A-23 Schedule M8 DGP, section 9.3.4 Prioritization of Conversion Projects.

Q24. What are the 4.8 kV Conversion projects included in this case?

A24. Table 1 below provides the high-level summary of the 4.8 kV Conversion projects included in this case. Detailed information for each of these projects is provided in exhibit A-23 schedule M6.

Table 1 Conversion Projects

Project Name	Municipality	Drivers
Cortland/ Oakman/ Linwood Consolidation	Detroit	Reliability & Operation: This project is part of a larger program to reduce 4.8kV breaker positions, transformers, and regulators. This will reduce O&M costs and provide spare components for equipment which is no longer manufactured. (LINWD SUB has 2 transformers, 2 regulators, and 11 breaker positions which are at or near end of life). This project will also eliminate associated underground cable
I-94 Substation and Circuit Conversion (Promenade)	Detroit	Safety: Significant assets are at high risk level including transformers, regulators, oil circuit breakers and disconnects. Along with 4.8kV and 24kV underground cable. Reliability: This area experiences wire down events which exceed the system average. Capacity: The Detroit Economic Growth Corporation has assembled the I-94 Industrial Park site – a 186-acre site north of I-94 between Mt. Elliott and Van Dyke on Detroit's east side. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation and logistics clusters. It offers access to major transportation assets. The site is a federally designated Historically Underutilized Business Zone and a state designated Renaissance Zone. Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. The new substation is required to serve the load growth in and around I-94 industrial park and allows for decommissioning of the aging Lynch, Lambert, and Pulford 4.8 kV substations. Operability: Promenade will have loop schemes and jumpering points.
Almont Relief and Circuit Conversion (Midas OH) - DO	Village of Almont, Almont Township, Lapeer County, MI	Safety: 4.8kV causes a higher safety risk in an event of a wire-down. Each Almont circuit is ~55 OH line miles. Reliability: Almont substation was built in 1956 and there are no spare parts available for the breakers. Capacity: Almont 4.8kV substation is 132% of its firm rating. ALMOT DC 304 is 93% of the day-to-day rating of 5.1MVA and ALMOT DC 303 is 87% of the day-to-day rating of 4.8MVA. Both ALMOT circuits, DC 304 and DC 303, exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Five Method of Service requests have been received for new load on the substation but there is no capacity to serve these requests. Operability: There are little to no jumpering options available for Almont circuits because Almont is surrounded by 13.2kV circuits and substations. In 2019, a cable failure occurred causing a breaker failure and an extensive outage for the Almont area. Due to the high loads, the substation was blocked from automatic throwover.

Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Buckler Circuit Conversion	Ann Arbor	Argo substation was built in 1926 and is a three transformer 4.8kV substation serving downtown Ann Arbor. Safety: 4.8kV Wire down elimination Capacity: The substation is currently unable to meet capacity needs in the rapidly growing downtown Ann Arbor area. The Argo circuits are limited to 3MVA based on the Distribution Design Order limit for a 4.8kV circuit. Argo substation is at 92% of its firm rating. The loading in this area will continue to increase which will eventually overload the substation and the circuits at Argo. Buckler substation was built to support current and future loads of Argo and the surrounding substations. Operability: Increased loading on 4.8kV circuits will inhibit the ability to transfer load.
McKinstry Sub Decommission	Detroit	McKinstry is a 24kV/4.8kV Class C substation. As part of the Gordie Howe Bridge Project, all of its circuits have been consolidated, converted and transferred to Zenon 120kV/13.2kV Class A substation. This specific project is to decommission McKinstry Substation, demolish the substation build and remove all associated equipment. Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: MCKNY has no load on the substation, all loads have been transferred elsewhere Other: Decommission (3) 24kV trunk lines. Decommission McKinstry Substation and demolish the building
Quincy Conversion	Yale	Safety: Power transformer sits on railroad ties instead of a transformer pad. Overhead stress from the leaning transformer causes safety concerns for those working on site. Other: QUNCY substation has low oil levels due to oil leaks, potentially causing future environmental impacts. QUNCY transformer is constructed on railroad ties that are rotten, causing the transformer to lean, adding stress to the overhead equipment.
Pinegrove Substation Relocation and Conversion (Neon)	Port Huron, St. Clair County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: PINGV circuits were last trimmed in 2020. Capacity: PINGV substation is 72% of firm rating of 20.6 MVA. IMLAY0302 exceeds the 4.8kV DDO of day to day loading limits. Other: MDOT has requested the removal of the Pine Grove (PINGV) substation in Port Huron to facilitate the expansion of the Blue Water Bridge Plaza. PINGV substation is ~100 years old and is a 4.8kV substation located at the base of the Blue Water Bridge in Port Huron. The substation and its associated infrastructure support 16.3MVA of load for 5,340 customers on nine circuits. PINGV substation is not a standard configuration as it has high speed ground switches instead of a circuit switcher on the high side of the transformer. This project will decommission the aging 4.8kV PINGV substation and build a new 13.2kV NEON substation. Constructing a modern distribution system with a new 13.2kV substation and more robust infrastructure will improve reliability and provide options for future capacity expansion in the Port Huron area.
Hawthorne Relief and Circuit Conversion	Dearborn, Dearborn Heights, Detroit, Garden City, Livonia, Redford Township	Hawthorne substation area is a dense, 4.8 kV service territory with many commercial and residential customers. Adjacent substations are Daly, Biltmore, Villa, and Glendale. Safety: Higher frequency of 4.8kV wire-down events (3X higher than the DTE system average) Reliability: Aging 4.8kV infrastructure at GLEND (built in 1947), BLTMR(built in 1953), DALY (built in 1954), VILLA (built in 1961) and HAWTH (built in the 1950's) Capacity: Overloaded substations with very high %firms HAWTH(128%), VILLA (110%) and DALY (106%), Limited load capacity to accommodate projected load growth in the area Operability: Limited jumpering opportunities due to geography coupled with heavily loaded nearby circuits
Hawthorne Trf #2 and Secondary Cable Replacement	Dearborn Heights	Hawthorne Substation is located in and feeds very dense areas of Dearborn Heights. To improve the loadability at the substation, this project will replace 750VCL secondary bus cable from both transformers with larger 1500KCM cable. The existing Position "H" 1200A disconnect will also be upgraded to a 2000A disconnect. Safety: Larger cable allows for higher ampacity ratings, replaces an older cable, which means that the cable is less vulnerable to failure and other safety issues. Reliability: VCL cable is recognized as a high-risk cable in the DTE system. Capacity: Substation is at 129% of firm rating, limited by secondary cables Operability: Over firm condition limits ability to transfer load and maintain service.

Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Crestwood Substation-Property	Dearborn	Other: Crestwood is an existing 120kV-13.2kV two transformer substation located in Dearborn, MI. The substation's property lease agreement expires in August of 2022. This request is to purchase this property from current land owner instead of extending the lease for another 49 years. Purchasing the property instead of extending the lease, would save approximately $1,000,000.
MAUME 8241 Downtown Clawson Conversion	Clawson	Reliability: Multiple frequent outages in 2020 and 2021 impacting Downtown Clawson. Several customer/town hall meetings involve Clawson city government, as well as Clawson DDA.
Power Line Conversion MADSN175L - W	Detroit	Reliability & Operation: Work is necessary to convert MADSN LPL 175 L-W standard to Power Lines (PL) and remove PIL 175L-W due to pilot cable failure. Pilot wire circuit is unjacketed, leaded cable. Numerous attempts to repair the circuit have been unsuccessful; cable continues to fail hi-pot test
GRFIN & WMSTN 4.8 kV ISO Conversions	Webberville and Williamston, Ingham County	Safety: Circuits have long 4.8kV (ungrounded) overhead miles because of the large 4.8kV ISO down areas. Many outages occur during storms and many wires were laying on the ground from the tornado in summer 2023. Reliability: GRFIN9799, GRFIN9883, and WMSTN9856 are some of the largest circuits in DTE and have limited jumpering points because of numerous ISO-down transformers limiting capacity and small conductor sizes on backbone limiting capacity. Capacity: Multiple method of services (industrial customer requests) have been received on GRFIN9799. Customer load creates a circuit DDO violation on GRFIN9799 and substation firm violation on GRFIN as the firm is surpassed before a project is executed. Williamston (WMSTN) substation is adjacent to GRFIN substation and is below its firm rating with capacity available. WMSTN DC 9856 also has capacity available on it. Load can be cascaded from GRFIN DC 9799 to WMSTN DC 9856 to mitigate the DDO violation. To facilitate this load transfer, 4.8kV ISO down pockets on both circuits must be converted to 13.2kV operation. Operability: There are no jumpering options for either of the two circuits due to overloads and low voltage after jumpering. Jumpering points are limited because 4.8kV ISO down pockets are limiting jumpering, these circuits are bordering Consumer's Energy circuits, and there are small overhead line sizes for the circuits' backbone. Other: MOS QPS 1 was received in 2019 and MOS QPS 2 was received in 2021. The buildings are located in an open industrial zoned area with other industrial customers nearby and more industrial customers are expected in the future.
SCOTN Circuit Consolidation	Detroit	Safety: flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers. After further investigation, the EPPM group at DTE concluded that all (36) position breakers will need to be replaced. The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits and to put the substation back to normal configuration. Reliability: In June 2021, flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers Other: The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits and to put the substation back to normal configuration.
Yale-Slater Decommissioning and Circuit Conversion	Yale, St. Clair County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: SLATR DC2652 customers report voltage as low as 110V. Capacity: SLATR substation is at 112% of Firm. SLATR DC2652 is at 112% of DD and exceeds the DDO limit of 3MVA. YALE's throw over circuit is unable to carry the load of YALE DC2615. YALE DC2633 is approaching the emergency rating of the throw over circuit soon will be unable to throw over. Operability: YALE and SLATR substations are surrounded by 13.2kV substations and therefore has limited jumpering capabilities. Other: SLATR substation lacks oil containment, potentially causing future environmental impacts. SLATR transformer is constructed on railroad ties that may add stress to the equipment.

Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Unionville Decommissioning and Circuit Conversion	Unionville, Tuscola County, MI	Safety: Existing 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Ageing substation equipment increases risk of failure. Capacity: Unionville substation is a 4.8kV distribution substation with two load carrying circuits. The substation is 111% of its firm rating and 91% of its emergency rating. Unionville substation is equipped with three single phase 500kV transformers which are the limiting element at the substation. Fairgrove substation is adjacent to Unionville substation. It is 116% of its firm rating and 86% of its emergency rating. Fairgrove substation is equipped with a 2.5MVA transformer which is the limiting element at the substation. Operability: Limited jumpering capabilities. Other: There have been 7 Method of Service requests in the Unionville area but the requests did not move forward due to the substanital upgrade costs which has led to repeated escalation and MPSC complaints.
Unionville DC 301 B1 Conversion - resolve voltage problem	Unionville	Safety: Existing 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Two residential customers filed MPSC complaints in January 2023. These customers are seeing a larger voltage flicker driven primarily by a residential on-demand water heater operating. However, the area has a history of motor start issues. The area is predominately agricultural. All sites have motors that operate within limits but collectively operate outside of limits. The issues will persist and complaints will continue until work is done to improve the circuit performance. Capacity: Unionville substation is a 4.8kV distribution substation with two load carrying circuits. The substation is 111% of its firm rating and 91% of its emergency rating. Operability: Limited jumpering capabilities.
Zenon Circuit Conversion Phase 2	Detroit	Zenon Class A substation was constructed in 2012 with dual winding secondary voltage (4.8/13.2kV) transformers as a means to quickly transfer 4.8kV load from McKinstry substation while facilitating future 13.2kV conversion. Zenon Phase 1 was driven by the construction of the Gordie Howe International Bridge (GHIB) crossing, and the McKinstry substation conflicts with the project. Four 13.2kV circuits were commissioned to either remove, consolidate, and/or convert portions of McKinstry & West End in direct conflict with the bridge plaza and the remaining McKinstry circuits were transferred to the 4.8kV side of Zenon. Due to recent flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8kV system in the area, and load increases driven by West Riverfront and Corktown development, the second phase of Zenon Conversions is to be initiated. The scope within this project was submitted for Round 1 of GRIP/IIJA grants in 2023. The Company was not awarded a grant in Round 1 and is submitting a modified application in Round 2 in 2024. If the Company is awarded a grant in Round 2, the timing of the project will be accelerated. Safety: Zenon Class A substation was constructed in 2012 with dual winding secondary voltage (4.8/13.2kV) transformers as a means to quickly transfer 4.8kV load from McKinstry substation while facilitating future 13.2kV conversion Reliability: Recent flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8kV system in the area Capacity: Load increases driven by West Riverfront and Corktown developments Operability: Completing this work will decommission WSEND and SCOTN substation along with their associated 24kV trunk lines
Calla Circuit Conversion	Dexter	Safety:4.8kV Wire down elimination Reliability: Customers on a DIMND circuit regularly experience frequent and long duration outages. For this circuit, the SAIFI 5 year average is 2.25 and SAIDI 5 year average is 681. Capacity: This circuit is also over the Distribution Design Order limit of 8 MVA. DIMND Substation is 137% of firm rating. Operability: Customers at the end of this circuit are about ten miles from the substation and regularly experience low voltage/power quality issues. It also has limited jumpering points and capacity in the area needed to relieve load at adjacent substations. Other: Calla Substation and one distribution circuit from Calla were commissioned in 2021. The second Calla circuit will be established to relieve load from Diamond Substation and address the circuit's issues (listed above).

Line No.

1 Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Lapeer - Elba Expansion and Circuit Conversion (Apollo)	Lapeer and Elba	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Lapeer and Elba substations have aging infrastructure and islanded 4.8 kV systems. Elba has problematic subtransmission infrastructure that has a history of poor reliability performance and limits shutdown capability for operation and maintenance. Capacity: Lapeer substation has a 13.2kV substation and a 4.8kV substation. The 13.2kV substation is at 107% of its firm rating. One circuit is at its day-to-day rating with another one approaching its day-to-day rating. Four circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Elba substation is a two circuit 4.8kV substation. It is 125% of its firm rating and the substation transformer exceeds its day-to-day rating. One circuit exceeds its day-to-day rating. General load growth has been strong in the area (6-8% in 2017 and 2018). Operability:Limited jumpering options are available at Elba substation since it is an islanded 4.8kV substation. Other: The Lapeer-Elba area has also experienced several low voltage and power quality issues.
Birmingham Decommission and Circuit Conversion	City of Birmingham, Troy, and Bloomfield Hills	Safety: Birmingham substation is at high substation outage risk Reliabilty: This project is to address the loading, aging infrastructure and substation outage risk at Birmingham substation. In addition, Quarton Rd. substation is a 1948 vintage switchgear. QTNRD circuits will be left as an island with no jumper capability after BIHAM conversion. QTNRD has significant number of customer complaints due to aging infrastructure. Capacity: The substation is operating at its substation firm rating. Any new customer load or hot summer days will place the substation over its firm rating and in violation of DTE Electric's Distribution Design Standards. Operability: Birmingham substation, mainly serving downtown Birmingham, has a high substation outage risk. The stranded load is estimated at 21 MVA after possible load transfers and 19 MVA after mobile fleet deployments.
Hemlock Decommissioning and Circuit Conversion - 01	Ann Arbor	Safety: Mitigating 4.8kV wire downs and replacing aging infrastructure including equipment at an approximately 67 year old substation will improve public and operational safety Reliability: SAIFI 5 year average is 1.00 and SAIDI 5 year average is 485. Capacity: Two circuits exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Hemlock (HEMLK) is a 4.8kV substation that is at 93% of its firm rating. The Ann Arbor area has a high percentage of electric vehicle adoption and has a goal of carbon neutrality and the elimination of natural gas heating; as a result, there is a 44% projected 15-year load growth in the area. Operability: Hemlock area is adjacent to both 13.2kV and 4.8kV substation areas which limits the jumpering capabilities for emergency restoration.
White Lake Decommissioning and Circuit Conversion	White Lake Twp., Springfield Twp., Highland Twp., Rose Twp.	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: WHTLK substation is an older substation with multiple at-risk equipment that need to be upgraded or replaced. There is also a 40kV capacitor (CAP1-1) that has multiple at-risk equipment in need of upgrade or replacement. The existing substation site is too small to support replacing major equipment. Capacity: White Lake (WHTLK) has a 4.8kV substation and a 13.2kV substation. Each one has a single transformer and a single circuit. The 13.2kV substation is 88% of its firm rating. The circuit exceeds the Distribution Design Order limit of 8MVA for a 13.2kV circuit. The 4.8kV substation is 100% of its firm rating. The circuit is at 100% of its day to day rating and exceeds the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Operability: White Lake circuits cannot be jumpered to one another because of the different operating voltages (4.8kV)

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Line
No.

Q25. Are there specific 4.8 kV Conversion projects you would like to discuss in more detail?

A25. Yes. In addition to the CODI 4.8 kV conversion projects that are discussed later in my testimony, I would like to highlight a couple of examples beyond what is contained in the exhibits to establish a deeper understanding of their scope, the rationale for making the investments, and the benefits customers will receive.

- I-94 Substation and Circuit Conversion (Promenade)
- Lapeer – Elba Expansion and Circuit Conversion (Apollo)

Q26. What are the drivers of the I-94 Substation and Circuit Conversion (Promenade)?

A26. The Detroit I-94 industrial park is expected to add new commercial and industrial customers to this area. This will result in increased loads that the current 4.8 kV system will not be able to adequately support.

The Promenade project will also provide relief to the increased capacity demand from the Detroit Public Lighting Department (PLD) conversions. This increased demand is caused by the transfer of customers from the former Detroit owned PLD system to the Company's system, resulting in overloads in some areas which created planning criteria violations with detrimental impact to operational flexibility and service reliability.

Also, the Promenade project address existing ITC transmission system loading violations. Currently, the ITC transmission system feeding the east downtown area has several Midcontinent Independent System Operator (MISO) loading violations

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which require mitigation. Engineers from ITC and DTE Energy collaborated to develop a set of projects to resolve the transmission system violations, with Promenade being one of these projects, resulting in a $130M reduction over the original proposed ITC solution.

Q27. What is the scope of the I-94 Substation and Circuit Conversion (Promenade)?

A27. This project is located on the eastside of Detroit and involves construction of the new 120 kV to 13.2 kV Promenade substation and the conversion and transfer of 4.8 kV circuits out of Lambert, Lynch, and Pulford to the new Promenade substation. In total 23 circuits (8 Lambert, 5 Lynch, and 10 Pulford circuits) comprising of approximately 100 miles of 4.8 kV circuits will be modernized and converted to six 13.2 kV circuits. Transferring the 23 circuits to Promenade will support the decommissioning of Lambert, Lynch, and Pulford substations. Additionally, the new 120 kV transmission feed will allow for the decommissioning of four 24 kV trunk lines with a weighted average age (WAA)[1] of 90 years.

Q28. What are the benefits of the I-94 Substation and Circuit Conversion (Promenade) project?

A28. The I-94 Substation and Circuit Conversion (Promenade) project eliminates existing ITC transmission system violations and provides 30% additional substation distribution capacity to serve residential, commercial, and industrial customers in the city of Detroit and in the area southwest of Detroit City Airport. The new 13.2 kV Promenade substation will support the decommissioning of existing 4.8 kV substations Lambert, Lynch, and Pulford; all of which have

[1] Weighted Average Age - The ages of the cables weighted by length.

surpassed the practical service life and are beyond 70 years old . Decommissioning these substations will remove at risk equipment, including 10 transformers, more than 20 regulators, more than 20 oil circuit breakers and disconnects, more than 20 miles of 4.8 kV underground cable, and more than 30 miles of 24 kV underground cable. In addition to capacity, conversion of the circuits will improve safety and reliability for the customers in this area with a projected 75-80% reduction in SAIDI and removal of all PLD primary and arc wire in this area.

Q29. What are the drivers of the Lapeer – Elba Expansion and Circuit Conversion project?

A29. Lapeer substation consists of 40 kV to 4.8 kV infrastructure and 40 kV to 13.2 kV infrastructure, while Elba is a 4.8 kV substation. The Lapeer 4.8 kV substation is approaching its firm rating at summer peak, and Elba substation has already exceeded its firm rating (124%), thus it is unable to accommodate any additional load growth in the area. Furthermore, there is no capability for Elba's downstream load to be transferred to an adjacent substation since it is an islanded 4.8kV area surrounded by 13.2 kV substations. This condition, if not mitigated, will result in extended restoration time in the event of an outage due to equipment failure.

Elba substation is almost 70 years old and is fed from a 6-mile 40 kV dedicated overhead line that has experienced poor reliability performance due to its location in a heavily treed right-of-way with limited shutdown capability for operation and maintenance. Due to the age of the electrical infrastructure in this area, there are several reliability and operability concerns.

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Q30. What is the scope of the Lapeer – Elba Expansion and Circuit Conversion project?

A30. This project is in Lapeer County, just north of I-69, and involves construction of the new 120 kV to 13.2 kV Apollo substation. Once the Apollo substation is energized, load from Lapeer, Hunters Creek, and Elba substations will be transferred to Apollo and four 4.8 kV circuits totaling 32 miles from Lapeer and Elba substations will be converted and consolidated to two 13.2 kV circuits. Following the transfer of all load, the Elba substation, the 40 kV subtransmission overhead line feeding Elba, and the 4.8 kV substation at Lapeer will be decommissioned.

Q31. What are the benefits of the Lapeer – Elba Expansion and Circuit Conversion project?

A31. The Lapeer – Elba project provides load relief and a 50 MVA capacity increase for new growth in Lapeer County. The decommissioning of Elba and Lapeer 4.8 kV substations will reduce outage risk by removing aging infrastructure from the system. Additionally, new jumpering capability will be established with the elimination of the 4.8 kV islanded system. Furthermore, reliability and power quality will be enhanced with the upgraded distribution circuits and elimination of the poor performing 40 kV overhead infrastructure feeding Elba.

City of Detroit Infrastructure (CODI) Conversion Program

Q32. What geographic areas of Detroit are addressed by the CODI program?

A32. As shown in Figure 3, the CODI program directly impacts the core Downtown, Midtown, and New Center areas of Detroit. Additional projects within the CODI

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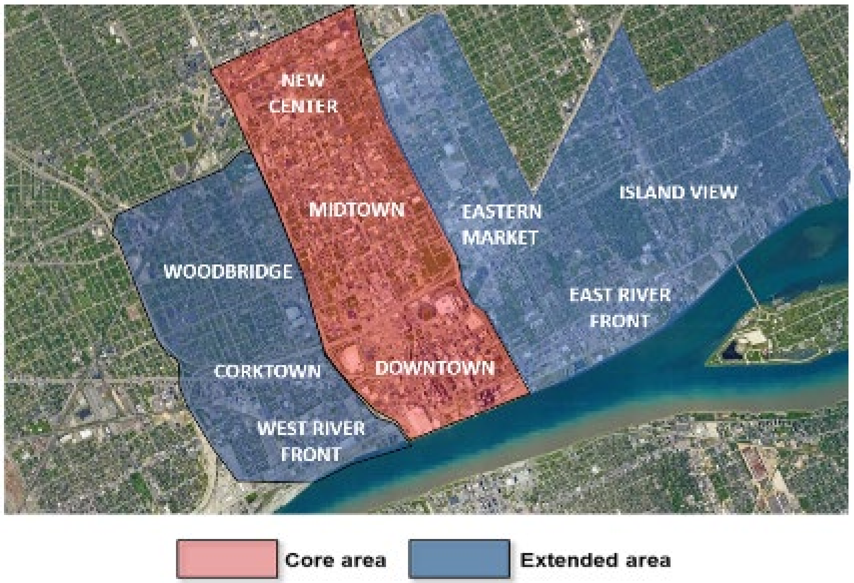
program will improve system reliability and safety in extended areas including Eastern Market, Corktown, Woodbridge, Island View, and the West and East River Fronts.

Figure 3 CODI Scope Area



Q33. How many customers are served in the CODI area?

A33. There are 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. Because customers are counted on a per meter basis, in some cases a single customer count in the CODI area could be a large commercial building, such as the Renaissance Center or a multi-tenant building with hundreds of residential tenants. In addition to residential housing, this area of Detroit is vital to hospitals, universities, tourism, and recreation in the region including shopping, major sports and cultural venues, and parks.

Q34. What are the drivers of the CODI program?

A34. The earliest electrical grid in southeast Michigan was developed in the downtown area in the city of Detroit. Significant portions of the electrical infrastructure in Detroit were placed in service in the early part of the 20th century, and much of that original infrastructure remains. For example, Garfield substation was constructed in 1930 and still provides electrical service to the Midtown area of Detroit surrounding Wayne State University and the museum district. The early electrical system architecture was designed to be extremely reliable; but as the age of the infrastructure has increased, so have the equipment failure rates. These customers continue to experience power outages and power quality issues from equipment failures related to aging infrastructure on the system (4.8 kV & 24 kV cable, netbank transformer, and substation induction regulator failures).

In addition to the challenge of aging equipment, the downtown CODI area has experienced 9.5% load growth (31 MVA) in the last decade, with the potential for an additional 10% load growth by the end of 2035. Additional load growth is mainly driven by the completion of downtown development projects in construction whose completion was delayed by the pandemic, known developer and economic development projects, and increased electrification.

The CODI area is extremely critical to the City of Detroit and the Michigan economy. Therefore, the system aging infrastructure, which is nearing one hundred years in service, must be upgraded to maintain its integrity and to serve the increasing load in the area. Some of the notable new load projects in the last decade are Little Caesars Arena, David Whitney Building, Q Line Light Rail System, Wayne State School of Business and Hillberry Theater Expansion, Book Tower, David Stott Building, Detroit Pistons Performance Center, and the Huntington Bank Tower. These along with dozens of other completed new build/renovations in the New Center, Midtown, and Central Business District areas of Detroit have created significant load growth and economic momentum in the CODI area, which will continue with the pipeline of future projects.

Q35. Are there additional drivers for the CODI program?

A35. Yes. The load growth realized over the last decade and projected in the future are not the only drivers of the CODI program. The aged 4.8 kV & 24 kV electrical infrastructure (substations, underground cable, manholes, network equipment, and other assets) in this area is experiencing higher failure rates which increases the risk of long-duration outages impacting customers and leading to high reactive maintenance costs. Eighty percent of the installed 4.8 kV and 24 kV infrastructure in the CODI footprint has been in service for over 60 years and is considered “at risk” as evidenced by the historical failure rate curve shown in Figure 4.

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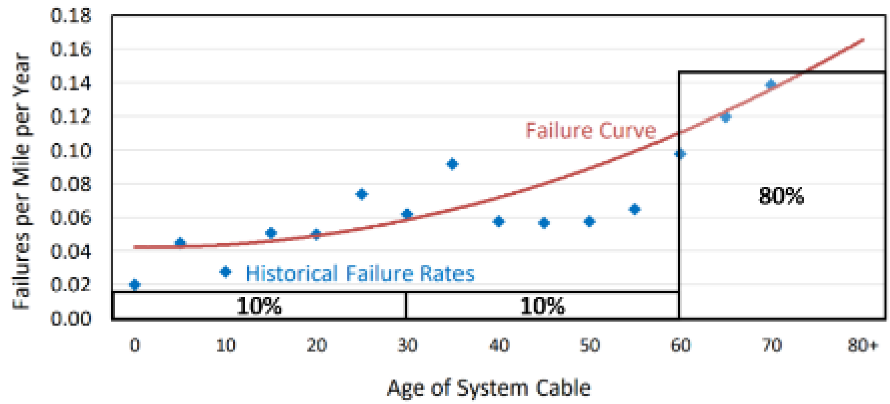
Figure 4 CODI 4.8 & 24 kV mileage distribution over system failure rate curve



The existing 4.8 kV multi-level in-building substations are space constrained to install or replace infrastructure with modern equivalents. Vintage equipment continues to be refurbished or repaired post failure and put back into service. This practice is not only costly, but it is also not considered to be good utility practice. The continued implementation of the CODI program is necessary to address this aging infrastructure to serve the customers safely and reliably.

Q36. What are the challenges with implementing the CODI program?

A36. Due to the complexity and the interdependency of the electrical infrastructure in this area, the Company developed the CODI program. The construction of new substations, upgrades to existing substations, converting the existing AC network system from 4.8 kV to 13.2 kV, and additional circuit upgrades must be sequenced and conducted in a robust, multi-year program as opposed to individual projects in isolation to each other. These projects require complex system shutdowns in a congested downtown district that must be managed carefully due to the critical customer loads that will be impacted, including hospitals, federal and municipal emergency centers, and multiple corporate headquarters. The CODI program is sequenced to perform the needed upgrades in a manner that is least impactful to customers.

Q37. What unique drivers that support prioritizing the CODI program to be completed in the next decade?

A37. The CODI area is served primarily by an all-underground system with manhole access located in busy city center streets. Its reliability is dependent upon the ability to have redundant capacity available on all power lines to transfer load in the event of cable failures or planned shutdowns on the distribution and subtransmission systems. This system is designed for N-1 contingency situations, which means that if a single trouble event is occurring on the system at any one time, the system is still able to serve all load. Manholes typically support multiple system cables, and a failure of one cable can impact adjacent cables resulting in cascading failures. Due to the amount of aging high-risk cable and equipment, the integrity, and the reliability of the underground system is compromised. This has resulted in an increased frequency of cases of multiple trouble events occurring simultaneously that are beyond the original system design criteria (N-1-1 and N-2 events) resulting in critical customer outages or complex contingency staging and planning of emergency equipment throughout downtown Detroit. Frequently when outage or next contingency events do occur in the CODI area, the Company has limited ability to respond and restore customers with alternative emergency measures; such as portable substations, diesel generators, or circuit load transfers given the space constraints of the congested downtown environment, inaccessible underground

Company infrastructure, and customer service gear located deep below grade in sub basements. These contingency plans are often not only time consuming but extremely challenging to execute.

When the CODI strategy was first conceptualized in 2015, the majority of the 24 kV and 4.8 kV cable in scope had a weighted average age of 65 years with some of the oldest sections being beyond 90 years of service age. With the current target completion date of 2035, sections of 4.8 kV and 24 kV cable will be in service for over 110 years at that point. With the failure rate of paper and lead cable increasing with age, these cables must be replaced to maintain the integrity and reliability of the system. The current pace of the CODI program addresses these necessary replacements in the maximum allowable timeframe and the Company continues to seek ways to increase efficiencies and accelerate implementation.

To ensure crew safety, DTE underground work rules prohibit personnel from entering manholes with swollen or leaking lead sleeves, shown in Figure 5, due to the possibility of an imminent failure, and therefore, these cables may need to be de-energized before entering.

Figure 5 Leaking & swollen sleeve examples

An increasing frequency of these types of adjacent hazards occurring simultaneously within the same manholes requires the Company to go to significant and impactful measures and implement emergency responses such as customer intentional interruptions, installation of temporary cable at grade, distributed generator staging installation in tight urban areas requiring street shutdowns, and expensive temporary re-routes of circuits, etc. to address safety issues and restore the system to normal.

The only method to completely mitigate the undergrounding reliability and safety issues is the replacement of old paper and lead cable with new ethylene propylene rubber (EPR) cable that does not have the same high failure rates and hazard issues with lead joints. The CODI program complements other grid investment programs by also reducing the totality of the 4.8 kV and 24 kV system that need to be replaced.

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Without these investments, the increasing failure rates of aged equipment, coupled with the load growth in the CODI area, will increase the frequency of outage events that affect large portions of the downtown system. These events will impact more customers and become more expensive and complicated to repair and restore.

Q38. What is driving the near-term AC Network replacements that are a critical part of the CODI program?

A38. The AC Network distribution system is recognized industry wide as the most reliable circuit topology due to its meshed design with multiple, parallel sources. This reliability advantage can only be preserved when the system is operated within its contingency design, which for the DTE Energy AC Network is N-1.

Due to the age of the system with components beyond their useful life, it is common for the Detroit AC Network to experience concurrent failures. These failures can lead to customer and system impacts including cascading low voltage issues, grid fires, manhole eruptions and customer outages. Table 2 lists the AC network outage events from 2016 through 2023.

Table 2 AC Network Outage Events (2016-2023)

YEAR	FAILURE EVENTS	N-1	N-1-1	N-2	OUTAGE EVENTS
2016	24	21	1	2	3
2017	21	20	1	0	1
2018	19	17	2	0	2
2019	27	22	3	2	5
2020	14	12	1	1	2
2021	15	11	3	1	4
2022	16	12	2	2	4
2023	16	15	1	0	1
TOTAL	152	130	14	8	22

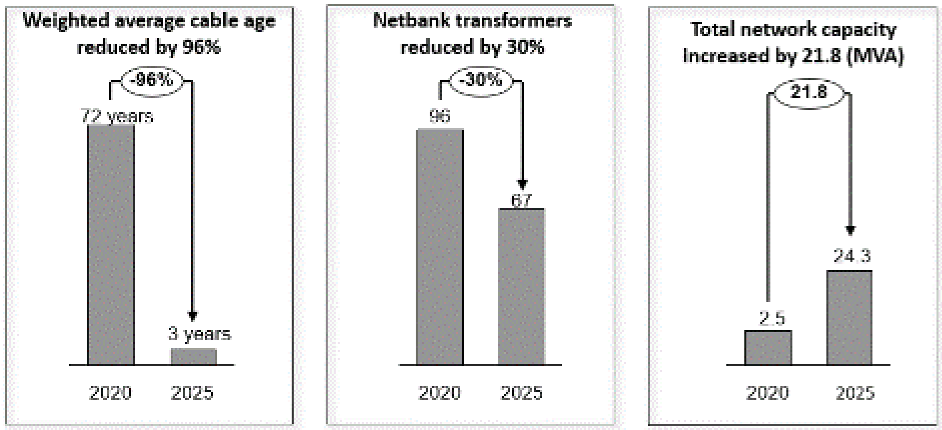
The downtown Detroit AC Network has experienced customer outages 22 times since 2016 or an average of 2.75 outages per year. This is concerning, as AC Network systems normally provide reliability that exceeds radial systems. Typically, a network customer can expect to be out of service once every 58 years and experience 4% of the interruptions of a radial underground system (New York Public Service Commission, 2009 as quoted in Smith & Moffat 2010) [2].

Downtown Detroit AC Network customers have not only experienced significantly more outages than typical indices, which will become more frequent as age related failure rates increase (as shown in Figure 4 above), but AC Network outages are also long duration events that are difficult to quickly restore as previously stated. Typical CAIDI for networks is 3.4 times longer than that of a radial system (New York Public Service Commission 2009 as quoted in Smith & Moffat 2010).

The existing AC Network system, operating at 4.8 kV, is capacity constrained in some local areas of growth based on cable size and number of network feeders, thus necessitating the conversion to a higher voltage class. Conversion allows for fewer network feeders to serve a given area of the system while increasing capacity. The Garfield Network Conversion project, as an example, reduces the number of netbank transformers required by 30% but increases Network Capacity by 21.8 MVA, all while reducing the weighted average age of the system primary cable by 69 years at project completion. The reduction in equipment will reduce associated maintenance costs over time. Figure 6 shows some of the Garfield AC network project benefits.

[2] D. Smith and J. Moffat, "EPRI Underground Distribution Systems Reference Book" (City: Publisher, 2010), Chapter 21, p. 21.

Figure 6 Garfield AC Network Project Benefits



Q39. What is the scope of the projects in the CODI program included in this case?

A39. The CODI program converts and consolidates substations, the AC network, and associated overhead circuits. This program will construct two new 13.2 kV substations (Corktown and Island View), expand three existing 13.2 kV substations (Midtown, Alfred, and Cato), and decommission five 4.8 kV substations (Charlotte, Walker, Howard, Kent, and Gibson). This program also converts and consolidates the AC network system, as well as converting and consolidating the associated overhead circuits from 4.8 kV to 13.2 kV. The program also includes decommissioning the aged underground 4.8 kV and 24 kV cables in the CODI footprint as shown in Figure 3. Table 3 provides a high-level summary of the projects in the CODI program with additional details provided in Exhibit A-23 Schedule M6.

Table 3 City of Detroit Infrastructure Projects

Project	Key Scope of Work	Estimated Timeline
CODI: Charlotte Network Upgrade	* Rebuild 30 miles of network feeder cable * Rebuild 7 miles of system cable * Replace or remove 83 netbank transformers *Convert 8 primary customers * Convert the circuits to 13.2kV * Decommission Charlotte substation	2016-2025
CODI: Targeted Network Secondary Cable Replacement	Replace targeted sections of the secondary network cable system that have a higher probability of failure	2017-2025
CODI: Midtown Substation Expansion	Expand 13.2kV Midtown substation by installing a 3rd transformer and a 12-position switchgear	2017-2024
CODI: Alfred Substation Expansion	Expand 13.2kV Alfred substation by installing a 3rd transformer and a 12-position switchgear	2018-2025
CODI: Corktown Substation	Build a new general-purpose substation	2018-2023
CODI: Garfield Network Upgrade	* Rebuild 36 miles of network feeder cable * Replace or remove 78 netbank transformers * Convert 24 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Stone Pool substation * Remove 4.8kV and 24kV cable and decommission Garfield substation	2019-2026

Table 3 City of Detroit Infrastructure Projects, Continued

Project	Key Scope Of Work	Estimated Timeline
CODI: Islandview Substation	*Construct a new 13.2kV substation * Convert 32 existing 4.8kV circuits from Walker and Pulford *Decommission Walker substation * Decommission aging 24kV cables and infrastructure	2020-2031
CODI: Kent/Gibson Conversion	<u>Kent Substation</u> * Rebuild 6 miles of system cable * Convert 1 primary customer * Convert 7 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 2 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 6 breakers and decommission Kent substation <u>Gibson Substation</u> * Rebuild 10 miles of system cable * Convert 22 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 4 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 8 breakers and decommission Kent substation	2021-2028
CODI: CATO Substation Expansion	Expand 13.2kV Cato substation by installing a 3rd transformer and a 12-position switchgear	2021-2027

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Table 3 City of Detroit Infrastructure Projects, Continued

Project	Key Scope Of Work	Estimated Timeline
CODI: Garfield Radial (Midtown Circuits)	* Convert 17 miles of overhead from 4.8kV to 13.2kV * Convert 11 primary customers from 4.8 kV to 13.2 kV * Convert and consolidate the circuits to 13.2 kV fed by Midtown substation * Decommission 5 miles of UG cable	2022-2026
CODI: Howard Conversion	* Rebuild 6 miles of network feeder cable * Rebuild 12 miles of system cable * Replace or remove 89 netbank transformers * Convert 26 primary customers * Convert 3 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown, St. Antoine, Cato, and Temple substations * Decommission Howard substation	2023-2032

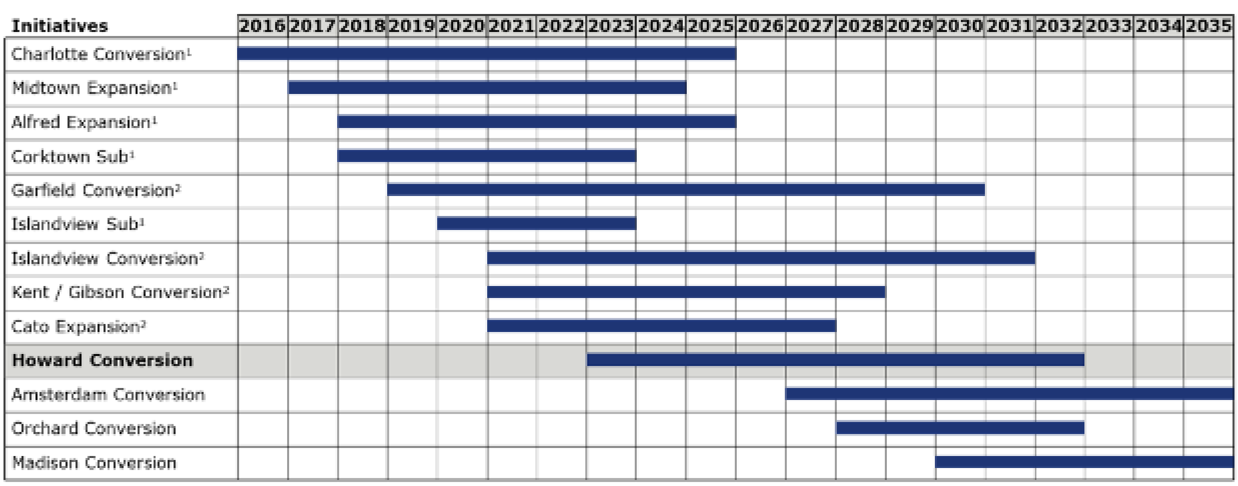
Q40. What steps is the Company taking to ensure that the CODI program is executed successfully to achieve the projected investment forecast?

A40. The Company's recently formed Project Management Office (PMO) is using developed project management expertise as well as updated processes and leveraging project learnings to ensure the successful execution of all DO capital projects, including the CODI program. The formation of this team focused on construction of investments is further discussed by Witness Kryscynski.

The Charlotte and Garfield AC Network conversion projects were able to identify the equipment, technologies, and standards that would be used in AC network and urban underground conversions going forward. As a result, in these early projects, much of the up-front investment was in foundational engineering and design considerations that will benefit subsequent projects. With this work now completed, the pace of field execution will be able to advance faster on inflight and future projects.

The initial years of the CODI project, as shown in Figure 7, were used to construct much of the 13.2 kV substation infrastructure, to support the subsequent projects including circuit conversion and the transfer load from the 4.8 kV CODI systems. During this timeframe, the construction was limited to only a few simultaneous projects (Midtown, Alfred, Island View and Corktown substation) and the CODI funding levels reflected these limited investments. Currently, in the ninth year of this program as shown in Figure 7, up to eight simultaneous projects of multiple labor resource types (substation, conduit/netbank construction, underground pulling and splicing, and overhead pre-conversion and conversion) are running at any one time in different areas of the CODI system. The CODI program can now support an increased level of spending because the different design and labor resources do not conflict with one another's execution.

Figure 7 CODI Strategy Initiatives and Projects



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4.8 kV ISO Conversion Program

Q41. What is an ISO down?

A41. In some areas, the Company operates portions of circuits at 4.8 kV fed from a 13.2 kV substation, known as isolation down circuits (ISO down). The reason for this grid configuration is that in some instances, there was a need to address immediate overloading on a circuit or circuits fed from a substation at which other circuits were not overloaded. The circuit overload issue can be addressed by building a higher voltage substation, typically 13.2 kV, and initially converting only the overloaded circuits, or portions of the circuits, to the higher voltage, while operating the remaining non-overloaded circuits at the existing voltage, typically 4.8 kV. Portions of the circuits which were not modernized and converted to 13.2 kV will include an isolation down transformer and continue to be served at 4.8 kV. Figure 8 illustrates a 13.2 kV circuit utilizing an ISO down.

Figure 8 "ISO" Down Example

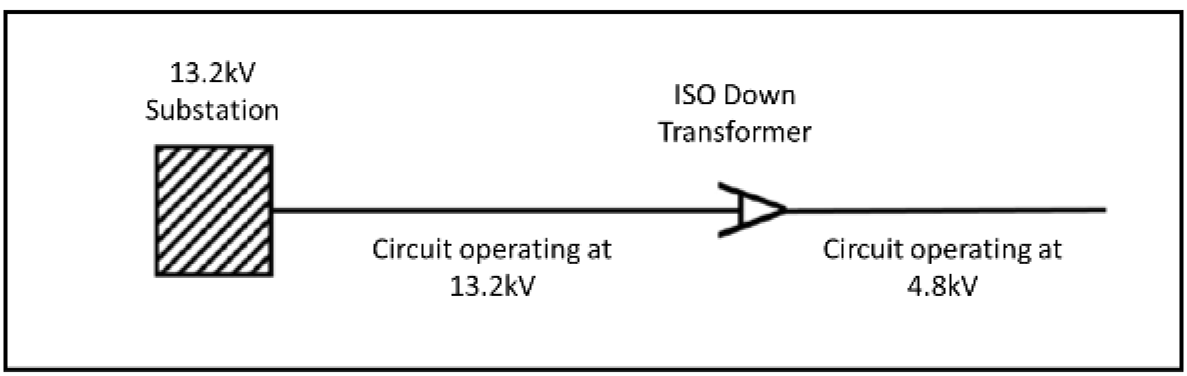

Table 4 provides the number of circuits with ISO downs, number of customers served, and the 4.8kV OH and underground line miles.

Table 4 Number of Circuits with ISO Downs

	Number of Circuits	Number Of Customers	Miles Overhead Circuit	Miles Underground Circuit
4.8kV ISO Downs	432	142,335	5,596	417

Q42. Why are ISO downs not considered a permanent solution to address overloaded circuits?

A42. The installation of ISO's has been a cost-effective and faster approach to address loading concerns at source substations without full conversion of the entire downstream circuits. This was always intended as a temporary measure. While at the time they didn’t face the overloads that caused the substations and some circuits to be converted, the 4.8 kV ISO downed areas of the circuits have not been upgraded or modernized and have the same characteristics of ungrounded 4.8 kV circuits fed from 4.8 kV substations. They have the same reliability issues, safety risks, and operational concerns, and face the same challenges when it comes to incorporating increasing EVs and DERs.

Q43. What is the scope of work for converting ISO down circuits?

A43. Similar to circuit conversions that are part of the Conversions program, the ISO down program is aimed at modernizing the 4.8 kV portions of the circuits to a higher voltage. The scope of work for the 4.8 kV ISO down conversions includes:

- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire.
- Rebuilding underground infrastructure as needed.

- Reconductoring overhead wires as needed based on new circuit configurations and existing wire size.
- Reconfiguring circuits and establishing new jumpering points.
- Installing controls and automation in the substations and circuits to our latest design standards
- Removing ISO down transformers.

Q44. What are the benefits of the 4.8 kV ISO Conversion program?

A44. The ISO conversion projects are expected to bring multiple benefits similar to full conversion projects, including safety improvements by reducing wire downs, improving reliability through newly updated equipment, enabling technology modernization, providing additional capacity; and avoiding costs associated with increasing failure of aging infrastructure. Like a full conversion and consolidation project, 4.8kV ISO conversions are expected to deliver up to 90% reliability improvements for the areas impacted, as described in detail starting on page SSD-14.

Q45. How are circuits in the 4.8kV ISO Conversion program prioritized?

A45. The 4.8kV ISO Conversion program is ranked as a whole using the GPM which considers substation firm rating, circuit overloads, wire downs per OH mile, substation risk, and energy justice (EJ), as discussed in detail by Witness Kryscynski. The Company prioritizes the order to address ISO down locations based on specific criteria, with safety being the primary driver in the prioritization efforts. Work is prioritized at the substation level, as it is more efficient to plan and perform the work for the group of circuits tied to the same substation. Each ISO

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down is scored based on the following factors, with total scores rolling up to the substation level:

1) Recorded wire downs;

2) Total substation SAIDI;

3) Total outage and non-outage events, such as low voltage, requiring the dispatch of a line crew.

Additionally, the Company recognizes that other priorities such as load growth and the need for operational flexibility are also important considerations in determining the execution order of ISO down conversion and will incorporate these considerations on as needed basis.

Work to begin 4.8 kV ISO conversions has been initiated on the four highest priority substations, which are shown in Table 5.

Table 5 ISO Conversion Rankings

Ranking	Substation	Community	4.8kV miles to convert
1	Camden	Pontiac	3.8
2	Kern	Pontiac	8.3
3	Gilbert	Romulus	5.8
4	Biddle	Wayne	11.7

Line No.

8.3 kV Pontiac Conversion

Q46. What are the drivers of the 8.3 kV Pontiac Conversion program?

A46. The Pontiac area is the only 8.3 kV in the Company's distribution system, as the system was acquired from CMS Energy in the 1980s (additional detail on the 8.3 kV system can be found in Exhibit A-23 Schedule M8 DGP starting on page 123). Unlike the 4.8 kV and 13.2 kV systems, contingency options to support alternate routing of power under an outage situation are very limited for the 8.3 kV system through jumpering. The 8.3 kV system is essentially an island surrounded by the 13.2 kV system, making it extremely challenging to transfer load from 13.2 kV circuits to 8.3 kV circuits and from 8.3 kV circuits to 13.2 kV circuits. This results in a high risk for stranded load in the event of a substation outage event.

Adding to this operational challenge, the 8.3 kV system is aged, and many replacement parts are no longer available. Due to the design configuration and timeframe when these substations were built, they have tighter, non-standard clearances between equipment. For Company employees to prevent arc flashes and maintain safe working conditions, total substation shutdowns are required when doing equipment maintenance, versus isolating a single piece of equipment as is done in other voltage substations. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails.

Additionally, the 8.3 kV conversion program is necessary to increase capacity, improve reliability, safety, and operability.

Q47. What is the scope of the 8.3 kV Pontiac Conversion Program?

A47. The 8.3 kV system is served by four substations: Bartlett, Paddock, Rapid Street, and Stockwell and their combined eighteen (18) distribution circuits. The plan to address the 8.3 kV system has been developed, starting with upgrading the system underground vaults, additional project detailed information is provided in exhibit A-23 Schedule M6 as well as Section 9.3.7 of Exhibit A-23 Schedule M8 DGP. The additional scope for converting the 8.3 kV system includes expanding the existing 13.2 kV Catalina and Wheeler substations to add capacity. Once the Catalina and Wheeler substation expansions are completed, the overhead and underground infrastructure from Bartlett, Paddock, Rapid Street, and Stockwell substations will be converted and transferred to new 13.2kV circuits.

Additionally, the 8.3 kV conversion program will decommission all four 8.3 kV substations in the Pontiac area. The removal of at-risk, outdated, and obsolete 8.3 kV equipment from the system will reduce emergent costs and improve response time for customer restoration.

Q48. What are the 8.3 kV Pontiac Conversion projects included in this case?

A48. The table below provides the high-level summary of the 8.3 kV Pontiac Conversion projects included in this case. Detailed information for each of these projects is provided in exhibit A-23 schedule M6.

Table 6 8.3 kV Pontiac Conversion Projects

Project Name	Municipality	Drivers
Infrastructure to support decommission of (8.3KV) sub - Pontiac OH	Pontiac	Safety: 8.3kV causes a higher safety risk in the event of a failure due to aging and obsolete equipment Reliability: Replacement parts are no longer available for 8.3 kV breakers, other substation equipment. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails. Capacity: The City of Pontiac is experiencing an economic rebound, with an estimated 40 MVA (37 percent) load growth in the next five to ten years. Operability: Because the 8.3 kV system is an island surrounded by the 13.2 kV system, it is impossible to transfer load from 8.3 kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3kV substation outage event.
Pontiac Underground Conversion	Pontiac	Safety: The aging 8.3kV system is Pontiac is obsolete and pose safety hazard for any repairs needed to be made. Reliability: Replacement parts are no longer available for 8.3 kV breakers, other substation equipment and equipment in the underground vaults due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails. Operability: The 8.3kV system serves 29.5MVA of load and over 7,000 customers. The largest services are delivered through 8.3kV rated underground equipment. These services contain customer-owned switchgear, fuses, and transformers. Replacement of the 8.3kV substations with 13.2kV infrastructure requires the replacement of these services with 15kV rated equipment to enable better operability.

Q49. What are the benefits of the 8.3kV Pontiac Conversion?

A49. Like the other conversion programs, the 8.3 kV Pontiac conversion program is projected to provide a net percentage reduction of up to 90% in customer minutes of interruption, wire downs, and trouble events. Additionally, converting the Pontiac system to 13.2kV will provide jumpering points from nearby 13.2 kV substations. This will improve system operability and reduce outage restoration time by allowing the Company to restore customers prior to repairing future damaged infrastructure (restore before repair). The expanded 13.2 kV Wheeler substation will provide capacity for future needs and better prepare the area for adoption of EVs and DERs.

Line No.

Subtransmission Redesign & Rebuild

Q50. Can you describe the Company's Subtransmission system?

A50. The Company's Subtransmission system is an interconnected web that transmits higher transmission voltage across the service territory to stations that step down the voltage to distribution levels to serve customers. The subtransmission system (operated at the voltages of 24 kV, 40 kV, or 120 kV) provides a vital service as each subtransmission circuit serves one or more distribution substations, which directly feed customers.

The design of the subtransmission system is intended to provide redundancy and therefore greater reliability to the feed points of the distribution substations. The redundancy provides continued service to the customers during a single contingency situation[3].

The Company's subtransmission system differs from that of most other utilities because it includes station equipment, radial, and network designs. The radial configuration, called a trunk line shown in Figure 9, has one source station which then feeds one or multiple substations. The network configuration, called a tie line shown in Figure 10, has multiple source stations, and feeds multiple substations.

[3] The contingency state exists when there is an unplanned loss/failure of a component of the electric power system (e.g., transformer, cable, wire or breaker).

The Company utilizes a coordinated system of automatic pole top switches (APTS) and line section breakers on the networked tie lines to isolate faults and maintain service to customers during single contingency failure situations.

Figure 9 Subtransmission Trunk Line Configuration

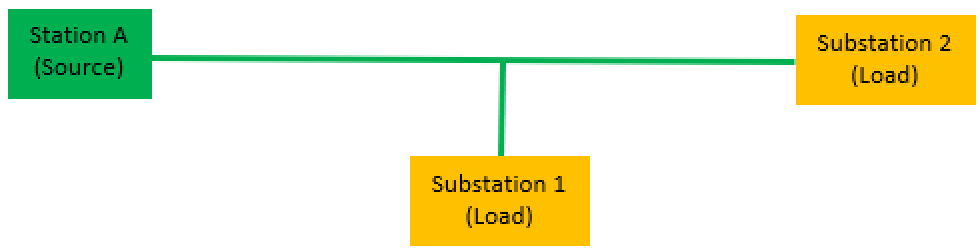
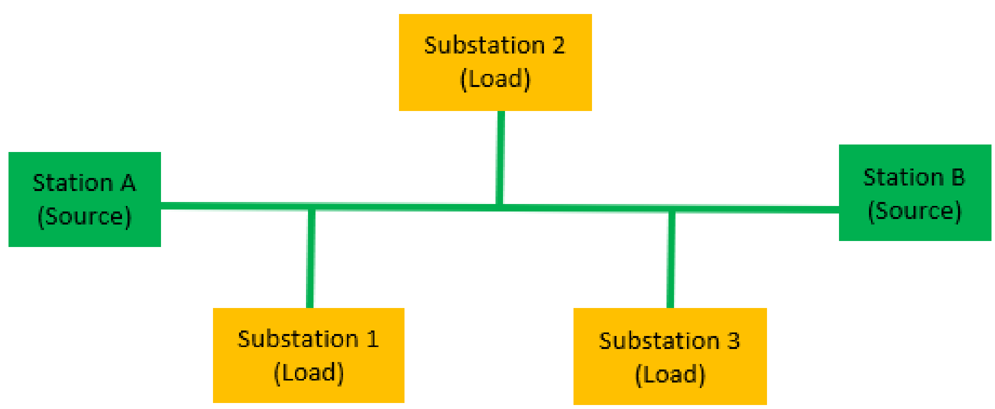


Figure 10 Subtransmission Tie Line Configuration



Q51. **What type of analysis was performed to determine potential capacity limitations in the subtransmission system?**

A51. Subtransmission Planning Engineers analyze the condition of the system annually to determine any existing or potential limitations to having adequate capacity to support customers in a single contingency situation. This analysis is conducted by utilizing industry-standard modeling software (PSSE & TARA), using both individual substation loads, and electric models used by the Midcontinent Independent System Operator (MISO).

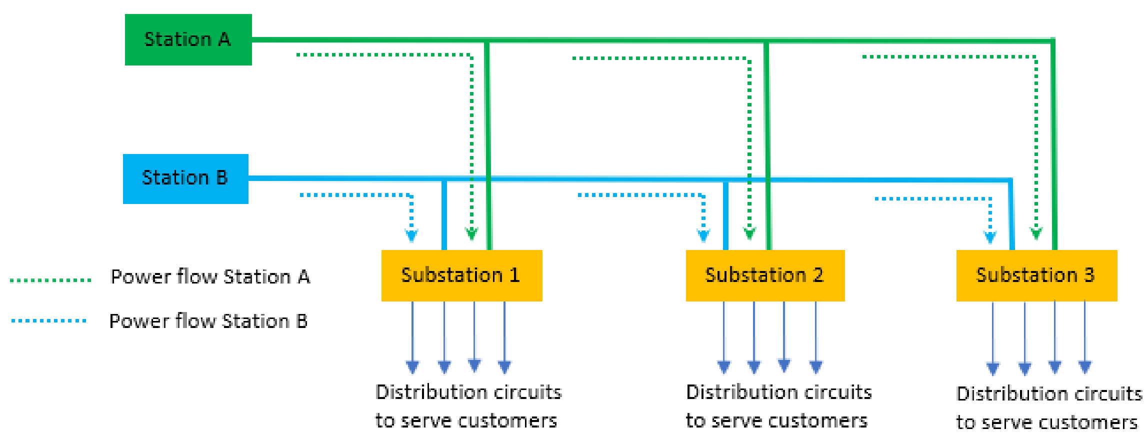
The electric models provided by MISO include multiple system loading scenarios, including current and projected future peak loading conditions. Using these models, the engineers run a study on each individual subtransmission trunk or tie line, with potential contingency situations assessed to identify all violations of subtransmission planning criteria. The planning criteria focuses on both thermal overloads and voltage violations under normal system conditions and during a single contingency configuration. A thermal overload indicates that load on the equipment on the circuit or station exceeds its rating, and a voltage violation indicates that the voltage on at least part of the circuit is no longer within an acceptable range. Similar methodology and guidelines are commonly used by other utilities when performing their capital planning.

Q52. Why does the company plan to a single contingency scenario for the subtransmission system?

A52. The company, consistent with standard industry planning approach, plans to a single contingency scenario to provide continued service to customers in an outage event. As an example, Figures 11 and 12 show a high-level trunk line configuration in normal and single contingency scenario respectively. In a normal configuration, two different trunk lines feed the multiple substations. Substations 1, 2, and 3 load will be split between the two subtransmission circuits, as shown in Figure 11.

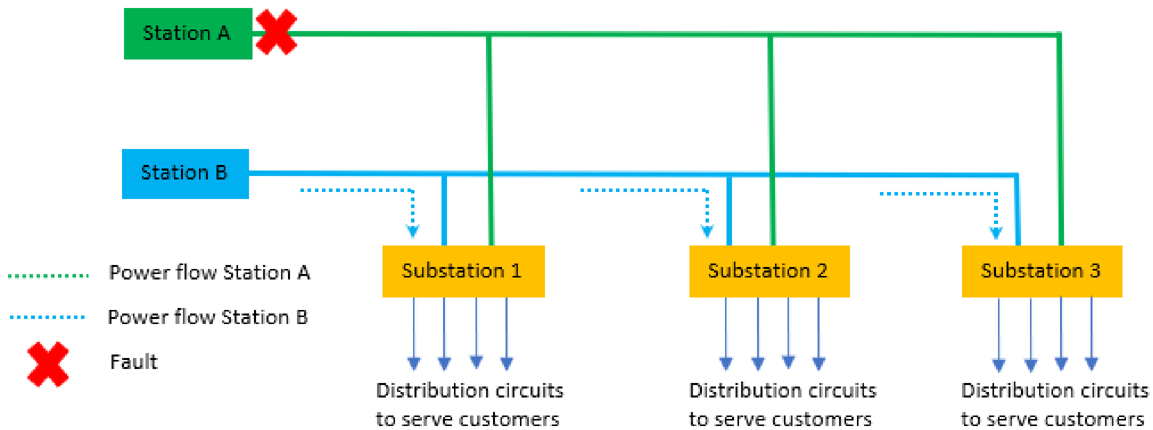
When one of the subtransmission circuits experiences an outage (single contingency), the second subtransmission circuit will have to carry all the load served by substations 1, 2, and 3 to prevent an extended outage, as shown in Figure 12. If this redundancy is not available, then the result is potentially a long duration outage that requires the deployment of costly mobile generation or portable substations to restore customers.

Figure 11 Subtransmission Normal Trunk Line Configuration



Line No.

Figure 12 Subtransmission Single Contingency Trunk Line Configuration



Q53. What are the challenges and issues associated with the subtransmission system?

A53. Similar to the distribution system, the subtransmission system is experiencing aging, beyond 80 years old in some areas, and storm related resiliency challenges, as well as increased loading in some areas, leading to loss of contingencies. Some areas of the subtransmission overhead system are in difficult-to-access, deeply wooded areas and along railroads, increasing the time and difficulty for restoring service or maintaining equipment. These factors are leading to an increased number of failures on both the overhead and underground subtransmission systems and lengthy restorations. Because of the role of subtransmission in powering and connecting substations in the larger grid, these failures can often result in much larger sustained outages as well as the loss of redundancy, depending on the system configuration. An outage event on the distribution system, downstream in the grid from the subtransmission system, can typically impact up to ~1,000 customers, depending on the size of the circuit. By comparison, an outage on the subtransmission system, because it's upstream in the grid, can impact multiple substations, which in some areas can result in more than 10,000 customers impacted.

Capacity analysis of the subtransmission system is performed annually, where actual and forecasted, loading is compared to a standard or target state, which is called "planning criteria." The Company performed an analysis on the subtransmission system that revealed approximately one-third of the circuits on the subtransmission system violated the Company's planning criteria. These violations have been/will be analyzed by the engineering team, and projects to resolve the capacity constraints are/will be developed.

In addition to current performance challenges impacting customer reliability, the analysis showed that the Company's aging subtransmission system overall is not adequate to serve short and longer-term needs, given its limited capacity and reliability performance. In some areas of the grid loads have increased over time and impacted customer outages by reducing the redundancy that is essential for continued reliability as well as operability of the system. Existing overloads and the aging equipment place loading constraints on the system. These constraints limit the Company's ability to plan for shutdowns required for system upgrade projects and routine maintenance to only be completed during periods of lower loading or through the deployment of portable equipment. These periods of lower loading are typically only during a few weeks in the spring and the fall season. The loading constraints also make it challenging to add new customers or provide additional capacity for existing customers with increased load.

Q54. What are the benefits of the Subtransmission Redesign and Rebuild Projects?

A54. A rebuilt, hardened, resilient subtransmission system will dramatically improve safety, reliability, and operability, and increase capacity. The resiliency of the overhead subtransmission system will be achieved by rebuilding to the Company's grade B standard which will harden against weather impacts such as high winds and lighting. The rebuilt overhead subtransmission system will have stronger steel poles and larger conductor to provide additional capacity and reduce voltage drop over long distances. The underground subtransmission reliability will improve due to the removal of at-risk or overloaded cables. Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures. Furthermore, the rebuilt subtransmission system will be designed to provide redundancy to reduce subtransmission level outages impacting customers.

This rebuilt and redesigned subtransmission system will support area load growth for existing and new customers, and with updated technology will provide the ability to support DER interconnections, including large-scale solar arrays. As the generation profile is expected to change with the integration of more DERs and the retirement of fossil generation plants, improvements to the subtransmission system will support the changing power flows on the system.

Q55. What is the scope of the Subtransmission Redesign & Rebuild program?

A55. The subtransmission redesign and rebuild program is focused on installing new station equipment, as well as rebuilding both the overhead and underground portions of the subtransmission system. The station work involves the installation of large new transformers, capacitor banks and associated equipment, which provides significant improvements to the system with additional redundancy and voltage support. The overhead work will be completed to updated, more resilient standards which include the replacement of aged wood poles with new steel poles, porcelain insulators with polymer clamp top insulators, and smaller and aging conductors with larger wires. The new stronger poles are able to withstand winds up to 90 mph resulting in a much more storm resilient system. The larger wire standard conductor delivers multiple benefits such as providing significantly more capacity on each circuit, reducing the magnitude of voltage drop over long distances on the system, and additionally providing approximately twice the strength of existing conductors to withstand contact with a tree limb during storms or other tree related events. Similar to overhead construction, the underground work consists of replacing at-risk or overloaded cable with new sections and rebuilding cable poles to new standards, supporting greater reliability for both the underground cables themselves, as well as preventing cable failure impacts to adjacent cables in the same underground section of the system.

Q56. How did the Company develop the Subtransmission Redesign & Rebuild Program?

A56. The Subtransmission Redesign & Rebuild Program was developed to address the identified planning criteria violations and the reliability performance concerns in the subtransmission system. To determine which subtransmission projects would have the greatest impact on reliability and resiliency of the system, the Company reviewed:

1) current system planning criteria violations, related to loading and voltage challenges;
2) future distribution system plans and loading projections; and
3) customer outages caused by subtransmission failures.

The Company then ranked the planning criteria violations based on severity, and projects were identified that could address the limiting elements on the system.

The scope of the projects and future subtransmission system configuration also support distribution system conversion plans that include the construction of new higher voltage and retirement of aged lower voltage substations. The distribution system conversion plans provide the necessary input to ensure the scope of the subtransmission projects will meet the requirements of our customers for decades to come.

In addition to planning criteria violations and future distribution system plans, the Subtransmission Planning engineers monitor the reliability of the system and identify circuits with multiple reliability issues related to subtransmission failures. These circuits are identified, and the subtransmission-related outages are analyzed to determine the most effective project to improve reliability performance. The planning engineers consider both existing routes of the lines that may require rebuilding in place, and sections where multiple wire down events have occurred, which might merit relocation. Based on their analysis, the planning engineers identify which sections to focus on for redesign and rebuild of the lines. The projects that address individual sections of subtransmission include rebuilding to the current more resilient construction standards and relocating the lines to road accessibility wherever possible.

Q57. How does the Company determine priorities when selecting circuits for Subtransmission Redesign and Rebuild program?

A57. The company's engineers select circuits for the Subtransmission Redesign and Rebuild program by evaluating system loading and reliability on an annual basis and rank the violations based on severity. DTE Energy considers six criteria when ranking the violations, described in Table 7. The first four criteria are part of what are called planning criteria violations. A planning criteria violation means that in either normal state or single contingency state, the system does not have adequate capacity to serve the existing load without exceeding equipment ratings or voltage standards. Projects are then developed to alleviate the violations.

Table 7 Subtransmission Priority Criteria

Subtransmission Priority Criteria	Definition
Load Loss for Single Contingency	Total load that will be shed when a subtransmission line can no longer support the substation and does not have a back-up or the back-up cannot support the load
Load over Emergency Rating for Single Contingency	Total load when a subtransmission line exceeds its emergency rating of its alternative route during an event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Total load that exceeds the rating of a subtransmission line during normal conditions
Voltage Violation	Consideration given to subtransmission lines that experience low voltage conditions when they are not in their normal configuration (i.e., due to an outage)
Strong Load Growth Prospect	Consideration given to subtransmission lines that are predicted to experience load growth
Reliability Impact	Consideration given for the reliability of the subtransmission lines based on total sustained outages, miles of circuit, exposure, construction standards & equipment total customers and total load served and ability to serve load from an alternate source

Consistent with other strategic projects and programs, the Subtransmission Rebuild and Redesign projects are prioritized using the GPM which is discussed in detail by Witness Kryscynski.

Q58. Can you please describe the Subtransmission Redesign and Rebuild projects included in this case?

A58. Table 8 provides the high-level summary of the Subtransmission Redesign and Rebuild projects included in this case. Detailed information for each of these projects is provided in exhibit A-23 schedule M6.

Line No.

1 ## Table 8 Subtransmission Projects

Project Name	Municipality	Drivers
Ann Arbor System Improvements: State Substation	Ann Arbor	Reliability: The existing distribution system in the Greater Ann Arbor area experiences frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance. This project, coupled with the other Ann Arbor System Improvements Projects Apex, Argo, and Buckler Circuit Conversions, will address these issues.
Ann Arbor System Improvements: Apex (Blue) Substation	Ann Arbor	Reliability: The existing distribution system in the Greater Ann Arbor area experiences frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.
Ann Arbor System Improvements: Argo 40kV Reconfiguration	Ann Arbor	Capacity: Due to high growth in Ann Arbor, ARGO substation does not have capacity to serve downtown Ann Arbor. This is part of the ARGO decommissioning project and will remove Argo from service (see related project Buckler Circuit Conversions).
Transformer High Side Protection Program	Bunce Creek, Chestnut, Newburgh, Northeast, Sunset, Wabash, Hancock, Hines, Pontiac, Spokane, Stephens, Troy, Wayne, Waterman, Wixom	Reliability: Several subtransmission and distribution transformers require the installation of high side protection, either a circuit switcher or breaker, to mitigate observed NERC reportable system issues during simulated contingency conditions that may result in the loss of service to 100+ MVA of customer load. These issues were discovered during annual studies performed by ITC and are required to be mitigated by NERC TPL-001-4 standards.
Subtransmission Redesign & Rebuild: Maxwell Amherst	Detroit	Operability: Amherst industrial substation was partially relocated to Maxwell station during an trouble/emergent job. The drivers for this project is to fully relocate Amherst industrial substation to Maxwell to meet the industrial customer service needs.
Subtransmission Redesign & Rebuild: Trunk 7106	City of Southfield	Capacity: Trunk 7106 is loaded to 134% of the equipment's summer normal rating and 126% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Farmington substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 2255	Detroit	Capacity: Trunk 2255 is loaded to 110% of the Summer Emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Glendale and Villa substations to prevent this equipment overload.

Table 8 Subtransmission Projects, Continued

Project Name	Municipality	Drivers
Subtransmission Redesign & Rebuild: Trunk 2237-ST	Redford	Capacity: Trunk 2237 is loaded to 100% of the equipment's summer normal rating and 110% of the equipment's summer emergency rating, violating the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at Six Mile Substation that will automatically shed load (10.3 MVA) to prevent from overloading equipment on Trunk 2237 and protect the equipment from any permanent damage
Subtransmission Redesign & Rebuild: Kennett	Madison Heights	Capacity: Trunk 7333 is loaded to 129% of the summer normal rating and 126% of the summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Brazil & Kenney substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	Sandusky	Capacity: Sandusky Transformer 101 is loaded to 126% of the equipment's summer normal rating, violating the Subtransmission Planning Criteria.
Subtransmission Redesign & Rebuild: Boyne	Macomb, Harrison, Clinton, Mt. Clemens, Chesterfield, New Baltimore	Capacity: Trunk 7909 is loaded to 120% of its summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will be automatically shed at Omega and Beach Substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 4105	Lexington, Croswell, Port Sanilac, Applegate, Carsonville	Reliability: TIE 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing Subtransmission lines.
Subtransmission Redesign & Rebuild: Tie 1568	Ypsilanti	Capacity: Tie 1568 is loaded to 99% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Crown substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 4217	Grosse Pointe, Harper Woods & Detroit	Capacity: Trunk 4217 is loaded to 123% of the equipment's summer normal rating and 116% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Grosse Pointe and Vernier substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 3509	Troy City Shelby SC Territory	Capacity: Trunk 3509 is loaded to 100% of the equipment's summer normal rating and 109% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Patton Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 4266	East Pointe	Capacity: Trunk 4266 is loaded to 108% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Savoy Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Praxair	301 E Great Lakes Ave, River Rouge	Operability: The normally open section disconnect at Praxair Substation is not rated high enough to interrupt the transformer load. Therefore, the customer's operation need to be interrupted everytime the switch need to be operated. The number of shutdowns currently required for DTE maintenance activities greatly impacts the primary customer's business and coordination of this work is challenging.
Subtransmission Breaker Short Circuit Violations	Bad Axe, Taylor, East Pointe, Detroit, Royal Oak, Milford, Warren, & Monroe	Safety/Reliability: 20 breakers on the Subtransmission system are in violation of the Subtransmission Planning criteria by exceeding their interrupting ratings. This could result in equipment damage or catastrophic failure of these breaker positions.
Subtransmission Redesign & Rebuild: Slocum	Trenton	Other: The Trenton Channel Power Plant, including all outlying structures and buildings are planned for retirement in 2022 with subsequent demolition. 3 trunk lines will be redesigned to remove all unused equipment that is currently being used to feed system service transformers at the power plant.
Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	Macomb and St. Clair Counties Shelby and Marysville SC Territories	Capacity: Tie 810 is a three-ended tie line consisting of 50 miles of overhead lines serving 10 substations. Low voltage levels are currently seen on this circuit due to significant circuit mileage and load.
Subtransmission Redesign & Rebuild: Oak Beach Capacitor	Port Austin	Capacity: Oak Beach and Caseville substations experience low voltage violations for an outage on Tie 3205, violating the Subtransmission Planning Criteria. Operability: The System Operations Center restricts shutdowns on Tie 3205 to prevent this low voltage. During an outage, manual load shed would be return the voltage to our operating limits.

Line No.

Table 8 Subtransmission Projects, Continued

Project Name	Municipality	Drivers
Subtransmission Redesign & Rebuild: Tie 810 (Gramer)	Macomb and St. Clair Counties Shelby and Marysville SC Territories	Capacity: Tie 810 experiences low voltages in multiple single contingency scenarios, which violates the Subtransmission planning criteria. Tie 810 experiences overloads in multiple single contingency scenarios. Operability: Load will automatically be shed at various substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 7504	Novesta Twp	Reliability: Customer complaints and escalations have been received due to frequent outages on TIE7504. Capacity: Substations served from TIE7504 experience low voltage during a single contingency, violating the Subtransmission Planning Criteria. Operability: 7 MVA of load is automatically shed on TIE7504 to prevent low voltage.
Subtransmission Redesign & Rebuild: Trunk 2308	Macomb	Capacity: Trunk 2308 is loaded to 99% of its summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Benson Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 3205	Pigeon, Caseville, Oak Beach, Port Austin	Reliability: TIE3205 has experienced frequent outages. This tie line is one of the worst performing circuits and it does not meet current design standards.
Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	Ann Arbor, Bad Axe, Chelsea, Commerce TWP, Fostoria, Grant TWP, Harbor Beach, Highland Park, Madison Heights, Monroe, Lenox, Rochester Hills,	Station locations do not have appropriate equipment to prevent backfeed onto the transmission system. Not having this equipment additional operating actions need to be take place creating additional work on DTE's side for switching, often reduces system reliability, and frequently can introduce additional restrictions on much needed shutdowns. This has resulted in ITC Operations requesting DTE to install reverse relay schemes at various locations.
Subtransmission Redesign & Rebuild: Tie 4104 North	Sherman and Sand Beach Townships	Reliability: TIE4104 has experienced frequent outages and deterioration of the conductor has been identified from testing.
Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	Bad Axe	Capacity: The tielines out of Bad Axe station experience low voltage violations for the loss of Bad Axe Transformer 101, violating the Subtransmission Planning Criteria. Operability: The System Operations Center restricts shutdowns on Bad Axe Transformer 101 to prevent this low voltage. During an outage, manual load shed up to 23.4 MVA would be return the voltage to our operating limits.
Subtransmission Redesign & Rebuild: Trunk 4245	Eastpointe	Reliability: The conduit crossing I-94 at 9 mile is damaged causing cable to become stuck in the ducts. Shores substation is at risk of losing their subtransmission feeds if cable failures occur.
Subtransmission Redesign & Rebuild: Trunk 4911	Lenox Twp. Chesterfield Twp. City of New Baltimore Ira Twp.	Capacity: Trunk 4911 experienced multiple overloads in a normal and emergency scenario up to 130% of the equipment rating, violating the Subtransmission Planning Criteria. Trunk 4911 also experienced low voltages in multiple emergency scenarios, violating the Subtransmission Planning Criteria. Operability: Load will be automatically shed at New Baltimore and Chesterfield substations to prevent equipment overload.
Subtransmission Redesign & Rebuild: Custer Republic	Monroe	Operability: Transformer 3 at Republic substation is 71 years old and carrying no load. Breaker equipment at Custer 68 years old. Reconfiguring the trunk lines between Custer and Republic will allow these under-utilized assets to be decommissioned.
Station Upgrade: Cortland Station Expansion	Highland Park	Reliability: Cortland Station was identified as a high-risk station in the Operational Risk Assessment. Operability: The existing station transformers at Cortland have physical constraints that do not allow for replacement in their existing locations. If a transformer failure were to occur, there are minimal options to serve the load if the next contingency were to occur. Many portable generators would be required.

Q59. What is the Subtransmission Small Projects and Reserve Program?

A59. There are times when the Company experiences issues on the subtransmission system that are less complex, and that unlike the larger subtransmission projects can be executed without extensive engineering and planning. These projects are generally smaller in scope and level of investment, requiring $500,000 or less in capital. The typical scope of work for these projects addresses thermal or voltage violations, under either normal or single contingency situations. Projects of this nature are identified during the yearly engineering analysis, which is the same methodology used to identify all the subtransmission projects under the Subtransmission Redesign and Rebuild program. Because the Company experiences this type of situation every year and they can be solved quickly without extensive engineering and planning, the Company has created a Small Projects and Reserve program. This program allows the Company to address these less complex issues on the subtransmission system in a short amount of time, without the more involved planning and engineering required for a larger, more extensive project. A high-level summary of these projects for 2024 is provided in Table 9

Table 9 Projects in the Small Projects and Reserve Program

Project ID	Municipality	Drivers
TRK 2508	Warren	Capacity: Trunk 2508 is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload.
TRK 2506	Warren	Capacity: Trunk 2506 section is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload.
Trunk 7114 -7115	Southfield	Capacity: Trunk 7114-7115 is loaded to 120% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Sargent and Gary substations to prevent this equipment overload.

Q60. How do customers benefit from the Small Projects and Reserve program?

A60. Similar to other subtransmission projects, the Small Projects and Reserve program will provide multiple customer benefits including safety, improved reliability and operability, and increased capacity, but within a shorter period of time due to the much more limited scope and compressed schedule required to address identified system issues. With the ability to address the system conditions and provide more immediate benefits to the customers with a relatively quick solution, the projects are executed shortly after identification instead of following the more structured project management steps of a larger project.

<u>Strategic Undergrounding Program</u>

Q61. Why is the Company interested in the undergrounding of circuits as part of conversion projects?

A61. The combination of aged overhead infrastructure and increasingly frequent and severe storms has resulted in negative reliability impact for many of our customers. A frequent question from our customers and other stakeholders in response to frequent outages has been "why not underground the lines?". The Company is interested in making undergrounding a viable option when circuits are being converted as that is the optimum time to take advantage of the synergy of the rebuilding process instead of just replacing the existing overhead infrastructure.

Undergrounding protects the electrical infrastructure from increased storm frequency and severity, thus providing resiliency and improving reliability. An undergrounded circuit also has safety advantages since there are no downed wires during storm events. Furthermore, over the life cycle of the assets, undergrounding can provide the benefit of reduced maintenance and repair costs due to eliminating the need for tree trimming, pole top maintenance, and in most storm cases, trouble response.

Through benchmarking, the Company has learned that many other utilities are also pursuing undergrounding of their existing overhead lines as a means to harden their systems for greater resiliency, increase reliability, and improve storm response.

To take advantage of this unique opportunity to be able to underground larger portions of the new converted system, the Company plans to conduct pilot projects, and initially seek out areas where there are construction synergies, which could be achieved by jointly working with municipalities or other utilities. This approach will allow the Company to learn, develop best processes for undergrounding in mature urban, suburban, and rural areas while focusing on reducing implementation cost. These pilot projects will also allow the Company to further demonstrate the benefits of undergrounding and determine when/where this design choice can be applied effectively.

Q62. How do the Strategic Undergrounding pilot projects differ from the Company's existing underground infrastructure and undergrounding that is done in new developments?

A62. The Company has been implementing underground residential distribution (URD) infrastructure since the 1970s for new construction subdivisions. Furthermore, the Company has a vast underground cable system utilizing the typically manhole construction in the city of Detroit and other urban areas in its service territory. Combined, over 30% of the Company's electric system is already underground. However, the Company has limited experience undergrounding existing overhead electrical infrastructure as part of the conversion process in mature and developed urban, suburban, and rural areas of the distribution grid. The rebuilding of existing overhead infrastructure to underground is significantly different in scope than installing underground infrastructure in a new development.

To learn and gain experience on undergrounding of existing overhead infrastructure, the Company is implementing undergrounding pilot projects. The main object of the pilot projects is to understand the challenges of undergrounding in a mature urban setting, define scenarios and situations when undergrounding can reap of rewards of safety, reliability, and resiliency benefits, and refine underground construction processes to gain cost efficiency on the installation. An additional goal is to analyze the longer-term benefits of undergrounding, to better support a refined benefit-to-cost analysis in the future.

Q63. Has the Company piloted undergrounding existing overhead lines?

A63. Yes. Per case U-20169, the Company was asked to explore potential pilot projects to eliminate rear-lot overhead infrastructure and its associated hazards. With the focus on reducing the safety hazards associated with rear-lot infrastructure, the Company initiated a pilot project on Appoline DC1346 (Appoline) in Detroit to move rear-lot overhead assets to rear-lot underground infrastructure, including the service lines. Appoline pilot project included 61 residential customers on two city blocks in Detroit. The scope of this pilot project included installation of approximately 1,300 feet of primary cable, six transformers, and underground services to residences.

Q64. What were the objectives of the Appoline pilot project?

A64. The objectives of the Appoline pilot project were to assess the safety improvements of undergrounding rear-lot overhead infrastructure, gather information on actual installation costs of undergrounding in a mature rural neighborhood, understand customer acceptance, and determine opportunities to improve cost and construction efficiency.

Q65. What was the timing of the Appoline undergrounding pilot project?

A65. The Company began engineering for the Appoline pilot project in 2018 and construction started in 2019. The Company initially had challenges with clearing rear alley structures and debris to gain access to the distribution infrastructure, and then ran into challenges with getting approvals from owners of rental properties as well as challenges posed by the Pandemic, delaying the final construction of a small number of customer service lines. The pilot project was completed in October 2023 with all customers converted to underground service and all related overhead infrastructure decommissioned. After internal benchmarking with DTE Gas, the Company took a more direct approach to connect all customers via an undergrounded service.

Q66. What were the lessons learned from the Appoline underground pilot project?

A66. From the Appoline pilot project, the Company gained valuable experience in undergrounding existing overhead infrastructure in a mature urban neighborhood.

With all overhead customer services undergrounded and the removal of rear lot overhead lines, the associated safety hazards of rear lot overhead lines were eliminated for this area. Additional learnings were that early customer engagement prior to construction is critical for success. The Company had difficulty in contacting the homeowners, often landlords at remote locations instead of onsite residents, to obtain approvals required to modify the electric service attachments to their homes. Before installation work could begin, the overhead infrastructure located in rear alleyways required extensive vegetation and debris removal. Furthermore, routing underground services from the rear-lot was very challenging due to garages, patios, and other customer obstructions that have accumulated from decades of neglect. Essentially every customer required a unique route to underground their service. Exhibit A-23 Schedule M11 provides detailed information for the Appoline pilot. Due to these challenges, the schedule, and the cost for the Appoline pilot were negatively impacted.

Q67. Was a benefit-to-cost analysis (BCA) completed for the Appoline pilot project?

A67. Yes. An initial BCA for the Appoline pilot project based on a partial subset of customer installations was presented in the MPSC case U-21297, however it was inconclusive due to limited customer data. Since that time, the Company collaborated with an independent consulting firm to create an updated BCA based on methodology utilized by other utilities in other states (such as IN, OH, IL, MD, FL, and OK). This analysis uses a long-term, present value methodology to compare the customer and utility benefits to the costs associated with investment options. The Appoline underground pilot project was compared with the alternatives of PTMM and overhead rebuild. The benefits of the Appoline underground pilot project included the present value of the avoided future costs of vegetation management, PTMM, and emergent reactive events. The model also included the benefits associated with the customer impacts of outages, using the Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) calculator. The LBNL ICE calculator is used by many utilities to approximate customers' costs of interruptions, although many including LBNL acknowledge that the model is conservative and underestimates the true costs of the outages. Then a benefit-to-cost ratio (BCR) was calculated for each investment option and compared to alternatives. The detailed BCA for the Appoline pilot is provided in Exhibit A-23 Schedule M13.

Q68. What were the results from the BCA for the Appoline pilot project?

A68. This analysis indicated that the BCR of the Appoline pilot project was lower than the overhead rebuild, but higher than PTMM. In this analysis a higher BCR indicates that there are more benefits than cost as a ratio, so either higher estimated benefits or lower costs of the project can raise the ratio. As this was an initial pilot project with initial learnings that included the substantial costs to remediate rear alley debris, this pilot BCR was not unexpected. Several factors contributed to the lower Appoline BCR. As discussed earlier and in Exhibit A-23 Schedule M11, there were challenges in getting approval from all the customers, in particular non-resident landlord owners. This delayed the project completion and caused additional mobilization and demobilization costs. Furthermore, to connect each of the customers' service from the rear-lot underground infrastructure required a unique design and process for each customer, adding additional cost for this pilot.

Adding on the cost for vegetation and debris removal to implement this pilot, these challenges further impacted the project cost. These specific learnings have been included in subsequent undergrounding work.

Q69. Are there additional important benefits that are not included in the BCA for the Appoline pilot project?

A69. Yes. Significant benefits of safety and resiliency for customers are not included in the financial BCR of the Appoline pilot project. With the rear lot overhead 4.8 kV conductors removed, the wire down hazard for this section of the distribution circuit has been eliminated. Furthermore, by undergrounding the overhead lines, the community and the customers also reaped the significant benefit of greater resiliency against the more frequent and more severe extreme weather events that could lead to prolong outages. The ICE Calculator described earlier, although meant to capture the benefit of incremental reliability, "may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and "cloud" computing, which may have led to an increase in interruption costs for both producers and consumers of these services. Therefore, the outdated vintage of the data presents concerns that underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method."[4] Both of these benefits, safety and resiliency, are not easily quantifiable in a way that matches present day customer needs or impacts. The Company will continue to collaborate with the MPSC and industry stakeholders to determine an appropriate way to quantify these benefits.

Q70. Is the Company pursuing other strategic undergrounding pilot projects?

A70. Yes. By collaborating closely with the city of Detroit, the Company developed a project to underground portions of the STLUS DC116 circuit in the Buffalo-Charles neighborhood. This is a bold initiative to underground approximately four miles of residential distribution lines using front-lot construction in a mature urban neighborhood with the intent of capturing additional benefits of joint gas and electric work.

Q71. Why was Buffalo-Charles neighborhood selected as the next underground pilot project?

A71. The Company considered multiple criteria in the selection process for the next undergrounding pilot. Selection criteria included wire downs per mile (safety), sustained and momentary outages for the circuit (reliability), impact to the community (energy justice), and construction cost. Over several meetings with City of Detroit officials, DTE Gas, and internal subject matter experts, six Detroit neighborhoods were reviewed and analyzed. The Buffalo-Charles neighborhood was very comparable with the other five areas that were evaluated. However, the Buffalo-Charles neighborhood was additionally attractive because it allowed the

[4] Sullivan, M.J., J. Schellenberg and M. Blundell (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Lawrence Berkeley National Laboratory Report No. LBNL-6941E, pg. 18

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Company the opportunity to work with DTE Gas, who are also doing underground gas main work in many areas of the city. Collaborating with DTE Gas will allow DTE Electric an opportunity to achieve synergies in the construction process to explore opportunities for further cost reductions and construction efficiency in co-located projects. By jointly working with DTE Gas, DTE Electric can utilize the same contractor for construction synergies that can lower the cost of the project. Furthermore, this is a benefit for customers in the project area, since gas main replacement and electrical infrastructure undergrounding is done at the same time, resulting in less disruption and impact on the neighborhood as compared with two separate projects at different times.

Q72. How has the Company engaged customers and other stakeholders in the Buffalo-Charles pilot project?

A72. Throughout the inception of this project, DTE has worked closely with the City of Detroit Mayor's office, City council, and other infrastructure partners. Per exhibit A-28 Schedule R1, the City of Detroit Mayor's office is very supportive of this undergrounding pilot because it will improve the quality of life for its residents through improved safety, resiliency, and reliability.

Once the specific project location was confirmed, a community town hall was held on September 13, 2023, at the Lasky Recreation Center. During this community town hall meeting, the company provided in-person communications with all customers and stakeholders to explain the scope and expectations of the project. Door to door communications preceded the town hall to let members of the community know about the project and to invite them to the event. Additional communications have also occurred throughout the construction including blog posts, direct mailings, and door hangers.

Q73. What is the scope of the Buffalo-Charles project?

A73. The scope is to underground portions of the STLUS DC1136 circuit in the Buffalo-Charles neighbor of Detroit to 13.2 kV capable front-lot underground residential distribution infrastructure and remove the aged 4.8 kV overhead rear-lot distribution equipment. In relocating to front-lot construction, the scope of undergrounding Buffalo-Charles is an enhancement from the rear-lot scope of Appoline. As the industry has evolved, peer utilities have adopted to use accessible, front-lot URD construction for undergrounding in an urban environment. Furthermore, front-lot URD has the potential for reduce construction cost.

The scope for the Buffalo-Charles pilot included constructing 3.9 miles of underground residential distribution to service 459 customers using front-lot construction. This project will install 4.3 miles of primary conduit, 3.9 miles of underground primary cable, 4.5 miles of underground secondary cable, and 8.9 miles of service cable. Additionally, this project will install 48 pad-mounted transformers, 153 secondary handholes, 459 junction boxes, 31 cable poles, and 12 ISO-UP transformers. Furthermore, this project will remove 2.8 miles of overhead primary, 3.5 miles of overhead secondary, 459 overhead services, and 3.5 miles of PLD/ARC wire.

Q74. What is the timing of the Buffalo-Charles project?

A74. After meeting with stakeholders throughout the summer of 2023, engineering and design were completed in late fall of 2023, with construction beginning in late October. The Buffalo-Charles project is expected to be completed by end of 2024.

Q75. Did the Company conduct a BCA for the Buffalo-Charles project?

A75. Yes. The Company used the same approach to conduct the BCA for Buffalo-Charles as it did for the Appoline pilot as described above. The detailed BCA for the Buffalo-Charles is provided in Exhibit A-23 Schedule M13.

The BCR results for Buffalo-Charles were similar to Appoline in that it was lower than the overhead rebuild, but nearly equivalent to PTMM. As with the Appoline BCR, the Buffalo-Charles project BCR result was not unexpected, given that the Company is still in the early stage of undergrounding pilots. Several factors contributed to the lower Buffalo-Charles BCR. The analysis used an initial cost estimate for implementing front-lot underground infrastructure in a mature urban neighborhood while removing old rear-lot overhead construction. The Company believes that actual project costs may come in lower with rigorous project management and the realization of project efficiencies with greater pilot experience.

Q76. Are there additional important benefits that are not included in the BCA for the Buffalo-Charles pilot project?

A76. Yes. Similar to the Appoline pilot project, significant benefits of safety and resiliency for customers are not included in the financial BCR of the Buffalo-Charles pilot project. When the rear lot overhead 4.8 kV conductors will be removed, the wire down hazard for this section of the distribution circuit will be

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eliminated. Furthermore, by undergrounding the overhead lines, the community and the customers will reap the significant benefit of greater resiliency against the more frequent and more severe extreme weather events that could lead to prolong outages. The ICE Calculator described earlier, although intended to capture the benefit of incremental reliability, "may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and "cloud" computing, which may have led to an increase in interruption costs for both producers and consumers of these services. Therefore, the outdated vintage of the data presents concerns that underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method."[5] Both of these benefits, safety and resiliency, are not easily quantifiable in a way that matches present day customer needs or impacts. The Company will continue to collaborate with the MPSC and industry stakeholders to determine an appropriate way to quantify these benefits.

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[5] Sullivan, M.J., J. Schellenberg and M. Blundell (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Lawrence Berkeley National Laboratory Report No. LBNL-6941E, pg. 18

Q77. How do the Company's undergrounding pilot projects' scope compare to other utilities that it benchmarked?

A77. Many benchmarked utilities are undergrounding as a means to make their grid safer and more resilient to increased frequency and severity of weather events. However, the scope of utility undergrounding varies based upon the utility strategy and geography. Several utilities in the West are undergrounding in and around defined high fire risk areas. The majority of these identified fire risk areas are in rural, less densely populated areas. Similarly, many of the utilities benchmarked in the South and Midwest are undergrounding in rural parts of their territory to improve storm response time and to improve their reliability metrics. The typical construction method used is trenching in road right of way and then either direct bury the cables or use conduit. With many of the utilities leaving the customer services overhead. DTE is one of the few utilities that is undergrounding in dense urban environments.

Q78. Why is the Company choosing to pilot undergrounding in dense urban environments?

A78. The main reasons that an urban environment was selected was based on the priority of safety, eliminate the hazards associated with 4.8 kV ungrounded delta system rear-lot construction, and to improve storm response for resiliency by reducing the number of customer services down. To achieve these objectives, the construction method utilized is to bore conduit for primary and secondary connections instead of trenching. To improve storm response and resiliency for single customer outages, often of longer duration in a large storm, the Company is also undergrounding customer service drops. These factors of the urban dense customer environment and undergrounding customer services will result the Company's

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undergrounding costs being higher when compared with another utility's scope of implementing in a rural environment without service drop replacement.

Q79. Is the Company considering additional undergrounding pilot projects?

A79. Yes. The Company believes that undergrounding brings a set of unique benefits and is of high interest to our customers. Undergrounding is the only investment option that eliminates the safety risk associated with downed wires and structures. Undergrounding provides the highest overall benefit in reducing emergent reactive costs and customer outages. Undergrounding is the most resilient option for severe weather-related events. Due to these advantages of undergrounding, the Company believes that it needs to conduct additional pilots to continue to learn and focus on reducing implementation costs, to increase the overall benefit to cost ratio.

The future projects are planned to involve a mix of geography; urban, suburban, and rural. Learnings from these projects will be used to refine the current benefit cost models to help identify segments of overhead infrastructure that are good candidates for undergrounding. This approach will allow the Company to develop a cost competitive undergrounding program.

Primary Deconductoring

Q80. What is Primary Deconductoring?

A80. Primary Deconductoring is the removal of unneeded or underutilized infrastructure such as aged small-sized primary wire, PLD arc wire, overhead transformers, and other pole top equipment in abandoned or blighted neighborhoods in the city of Detroit.

Q81. What are the benefits of Primary Deconductoring ?

A81. The benefit of removing overhead lines that are not fully utilized, and any associated arc wire, reduces wire downs and improves safety in that area. Removing unnecessary overhead lines also eliminates the potential for power outages caused by those lines failing or being damaged thus improving reliability in the area. In some situations, primary deconductoring may require the installation of new secondary lines to serve the few remaining homes in the neighborhood. When new secondary lines are installed, they are constructed to the current standards.

Q82. What is the scope of work for Primary Deconductoring?

A82. The scope of work for Primary Deconductoring includes the removal of unneeded or underutilized infrastructure such as aged small-sized primary wire, abandoned arc wire, OH transformers, and other pole top equipment in abandoned or blighted neighborhoods. In addition, where necessary the Company will reconductor secondary wires and upgrade transformers and other pole top equipment, and where possible install equipment in truck accessible locations.

Q83. Has the Company completed the Primary Deconductoring pilot?

A83. The Company has completed pilots on two circuits in 2023. In Case No. U-21297, the Commission approved $1.8M of investment in 2022. The Company had an additional 36,000 of investment in 2023 to complete these two pilots.

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Q84. How is Primary Deconductoring used as part of current circuit planning?

A84. Per the success of the two completed pilots, the Company has rolled primary deconductoring into the 4.8 kV Hardening program and 4.8 kV Conversion projects, were applicable.

System Loading Projects

Q85. Can you describe a system overload?

A85. System overloads occur on a circuit or substation when there is insufficient capacity to meet customer demands while maintaining grid operation within equipment operating ratings. Capacity needs are analyzed for two conditions: normal state and contingency state. The normal state exists when all equipment and components are in service and operating as designed. The contingency state exists when there is either a temporary, planned equipment shutdown or the unplanned loss/failure of a component of the electric power system (e.g., transformer, cable, or breaker). Under contingency state conditions, equipment in the rest of the system may see an increase in loading to compensate for the out-of-service equipment, delivering additional power above normal state.

To meet the two capacity needs of the system, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above its designated ratings can cause immediate failure or accelerate end-of-life and is considered an overload. DTE definitions for day-to-day rating, emergency rating, and substation firm rating are consistent with industry definitions such as those available from National Electrical Reliability Corporation[6],

- The day-to-day rating (for normal state conditions) is the load level at which the equipment can be operated for its expected life span.
- The emergency rating (for contingency state conditions) is typically higher than the day-to-day rating and indicates the load level that the equipment can operate for short periods of time only. Operating towards the emergency rating adds stress to the equipment and may shorten its lifespan. If a piece of equipment exceeds its emergency rating, the Company's ESOC personnel will take immediate steps to transfer load or shed load if necessary.
- Substations also have a firm rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of any substation equipment that is required to serve the load; such as incoming subtransmission feed, transformer, and secondary cables. Figure 13 below shows an illustration of a substation with a firm rating of 45 MVA. The substation consists of 2 transformers. Transformer 1 has an emergency rating at 45MVA and transformer 2 has an emergency rated at 50 MVA. Transformer 1 has the lowest emergency rating of the equipment inside the substation, therefore 45 MVA is the firm rating of the substation in this example. Under normal operation both transformers serve customer load that they are designed to serve. In a single contingency situation, such as the failure of a transformer or loss of a

[6] Glossary of Terms Used in NERC Reliability Standards, available at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, accessed March 12, 2024

subtransmission feed, automatic operations will occur within the substation and customer load will continue to be served to avoid a large, sustained outage. Figure 14 below shows the same substation operating in a single contingency situation where transformer 2 is down. Transfer 2 breaker is opened to isolate and deenergize it. The tiebreaker is closed to allow customer load to be rerouted through transformer 1. The total load on the substation is below firm rating so all the customers can be fed from transformer 1. If the total load on the substation is over the firm rating, the extra load on transformer 1 would cause it to operate above its emergency rating. Typically, the Company does not operate its equipment at or above emergency ratings. To prevent operating at or over emergency rating, the loading on Trans 1 would need to be reduced. This would require load to be shed and customers would experience an outage until the situation is remediated.

Figure 13 Substation in Normal Configuration

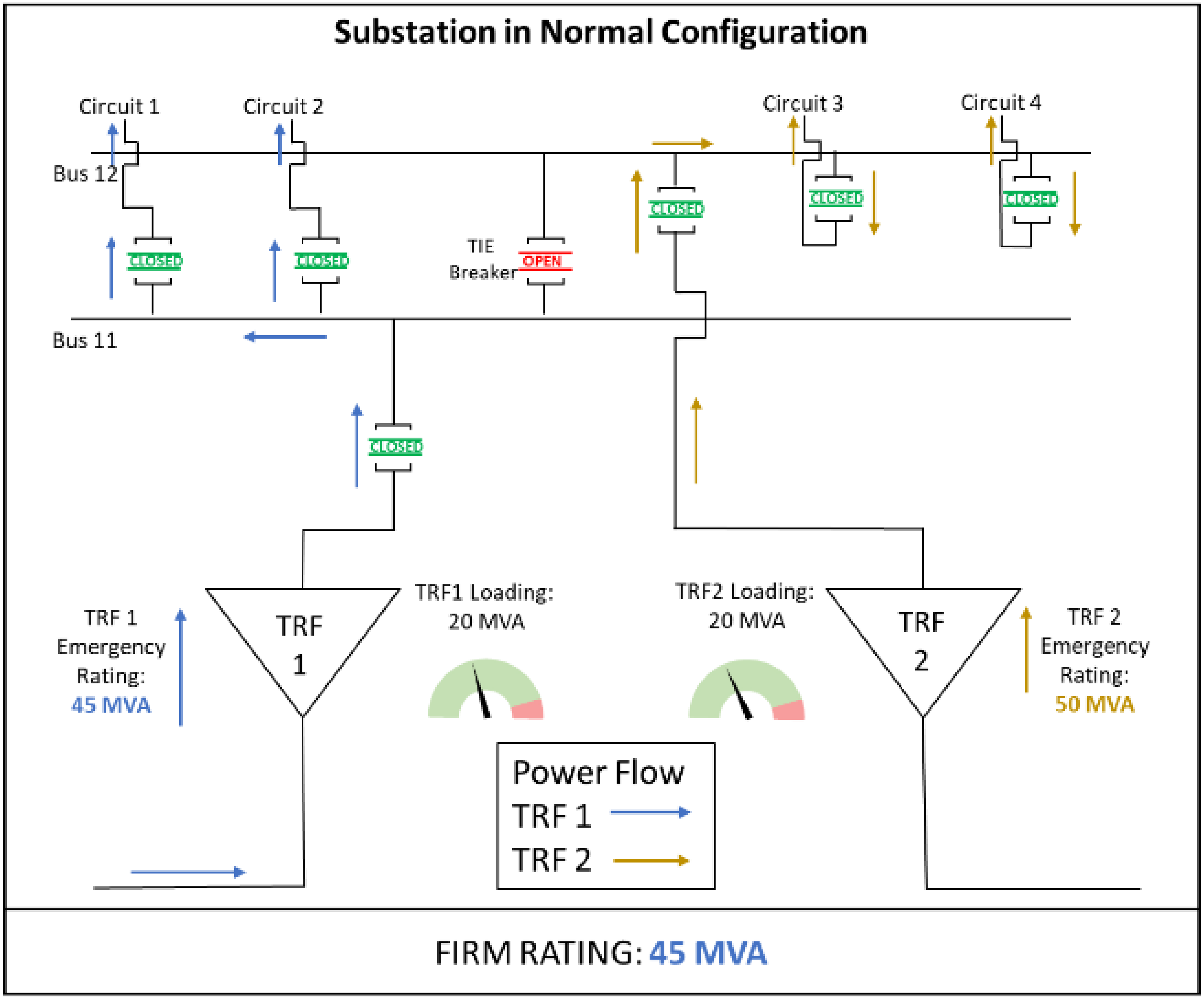
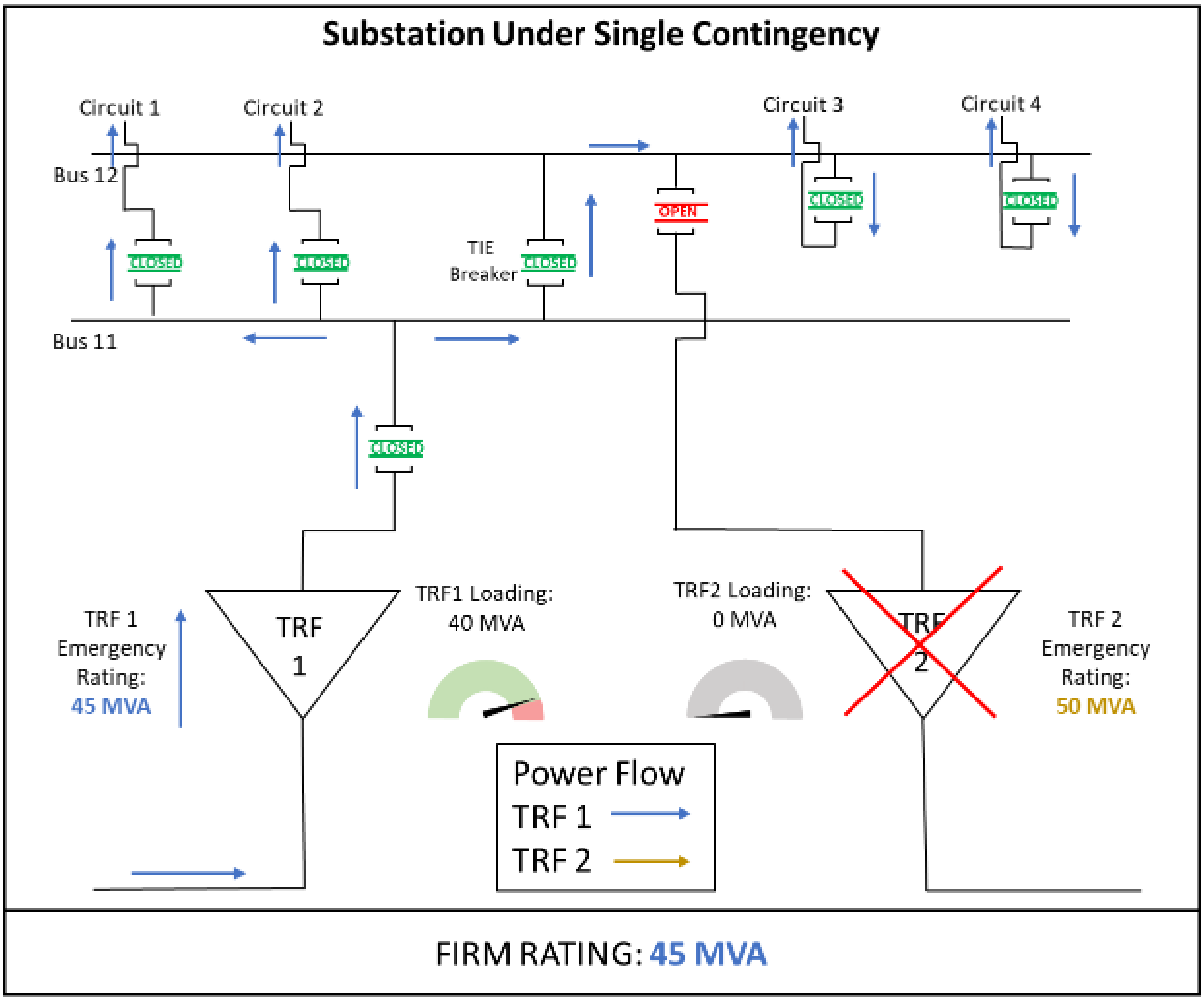


Figure 14 Substation under Single Contingency



Q86. What are the challenges and issues with system overloads?

A86. When equipment is operated in a system overload condition, the equipment is stressed, and useful life is reduced. Additionally, this impacts system operability by limiting jumpering abilities needed to support customer reliability during outage events. Without jumpering capabilities to adjacent circuits, outages will be sustained for longer periods of time because the failed equipment must be replaced to restore customers. Furthermore, overloaded equipment can also increase the probability of emergent failures leading to customer outages.

Also, when there are overloads on the system it is challenging for the Company to serve new customers and provide the ability for existing customers to expand, therefore, in areas where system overloads exist, the absence of electrical capacity inhibits DTE's ability to support economic growth in SE Michigan. This challenge is also expected to increase with increasing loads brought by electrification and distributed generation as part of the clean energy transition.

Q87. How does The Company forecast and mitigate system overloads?

A87. The Company conducts annual Area Load Analysis (ALA) on all distribution circuits and substations to determine where there are overloads on the system. Based on a study of historical ALA's, approximately one-third of distribution substations have loading constraints. This includes substations operating over its firm ratings and/or circuit equipment working near or over its day-to-day rating during peak hours.

In areas that have seen and continue to see steady load growth, capital investments are required to prevent overloads. These projects are categorized as System Loading projects. The projects in the table below are proposed within the System Loading category with additional details within Exhibit A-23 Schedule M6.

Table 10 System Loading Projects

Project Name	Municipality	Drivers
Brest Substation	Monroe	Project is completed. Project Drivers were: Safety: Concrete and support structures at BREST substation required significant repair and oil breakers were at end of life. Operating safety & risk of prolonged customer outage. Capacity: secondary driver to increase capacity while decommissioning 4.8kV switchgear
Carleton Substation Upgrades	Ash Twp	Project is completed. Capacity: Carleton substation 196% of the maximum loadability. Transformer 2 is at 112% of its day to day rating. CARLT DC 312 is at 124% of its day to day rating and exceeds the 3MVA distribution design order limit for a 4.8kV circuit. Operability: Limited jumpering options due to substation and circuit loading. Failure can lead to customer outages/stranded load.
Grayling	Shelby Twp	Project is completed Capacity: Grayling substation is a heavily loaded 120-13.2kV substation providing service to the high growth commercial and industrial businesses along 23 Mile and 24 Mile in Shelby Township. All Grayling circuits are at capacity Reliability: Improve SAIDI by 50% Operability: Grayling substation is surrounded by overloaded substations
Prospect	Superior Twp	Capacity: Prospect Transformer 1 has exceeded the day-day rating at 119% in 2020 and substation at 119% of Firm Rating. As Engineering developed scope for this project, upgrades at Prospect have been cancelled as all load from Prospect substation will be served by the upgraded Grenada System Loading Project. Load from Prospect has temporarily been transferred to adjacent circuits to mitigate overload conditions.
Mandy 307 Load Transfer	Royal Oak	Reliability and Operability: Mandy DC307 is currently 126% of its firm rating. The day-to-day circuit rating is violated since 2016. The day-to-day rating for Mandy DC307 is 2.7 MVA and the peak for the circuit is 3.4 MVA. The circuit Mandy DC307 is surrounded by a dense tree area creating significant amount of outages.
Mack Transformer 102	Detroit	Project is completed. MACK TRF102 installation was completed to allow for the repair of inoperable LTCs on MACK TRF101 and MACK TRF104 without putting customers served out of MACK at risk for a long outage. Upon completion of the needed repairs TRF102 is to operate in standby to provide additional reliability. This would have put 101MVA (26,000 customers) at risk for a long outage if the other TRF were to fail during the shutdown.
Globe	Vassar Twp, Tuscola County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: GLOBE is at 2.4 MVA, or 75% of its DD rating. Vassar Township has been issuing permits for Indoor Agricultural Centers, resulting in high load demand, which cannot be supported by existing Globe infrastructure. Operability: No jumpering option available between Globe and nearby Sheridan substation. Other: GLOBE TRF size needs to be increased to provide load relief opportunities for future SHRDN substation. Active customer load addition requests in the area pending project completion.
Brown City	Brown City, Marlette and Imlay City	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: Substations over firm rating. Circuits approaching Day to Day rating Operability: BRCTY substation is a 4.8kV distribution substation and surrounded by TCOMA substation, which is a 13.2kV distribution substation. This limits jumpering options for BRCTY substation.
Port Sanilac	Sanilac county	Safety: Aging infrastructure has a risk of failure. 4.8kV causes a higher safety risk in an event of a wire-down. Reliability: Forester has an aged Line Section Breaker (LSB) in need of replacement. 3-333kVA pole mount transformers at Forester are also at-risk equipment at Forester substation. The circuits at Port Sanilac are limited by substation regulators that are considered at-risk with no spare parts available. Capacity: Substations over firm rating. Circuits over Day-day rating.Forester substation is a Class T substation with a single circuit. Operability: There is limited/no jumpering options during peak since Port Sanilac is surrounded by Forester and Applegate substations, both of which are approaching/exceeding their substation transformer limits. Failure can lead to customer outages/stranded load.
Richmond/Armada	Richmond and Armada	Safety: 4.8kV causes a higher safety risk in an event of a wire-down. Reliability: The 4.8kV switchgear at Richmond substation was installed in 1956 and is the only oil filled truck type outdoor switchgear remaining on the DTE system. The breakers along with the CTs have no spare parts available. Capacity: Substation over firm rating. Circuits over distribution design order. Operability: Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.

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1 Table 10 System Loading Projects, Continued

Project Name	Municipality	Drivers
Cody	South Lyon / Lyon Township	Safety: There are large 4.8kV (ungrounded system) ISO-down pockets, which are a hazard to the public. Reliability: The last tree trim was in 2015 which explains the second largest outage factor of trees. Capacity: Substation over firm rating. Circuits exceed distribution design order. Additional load growth expected due to new development. Operability: Due to loading there are no jumpering options inside of sub and little no jumpering options outside of the sub in the case of a failure. Failure can lead to customer outages/stranded load.
Otsego/Capac/Shaw	Imlay Twp	Capacity: Substations over firm rating. Circuits exceed distribution design order limit. Operability: Substation throwover is blocked due to loading. Little to no outside jumpering available. Failure can lead to customer outages/stranded load. Other: Execution of the project is key in providing capacity on OTSGO substation to initiate a different project to move IMLAY load to OTSGO and allow for decommissioning of IMLAY.
Macomb Substation	Clinton Twp, Macomb County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: Substations over firm rating. Circuits over Day to Day rating. Circuits exceed Distribution design order of 8MVA per 13.2kV circuit.
Grenada	Ann Arbor	Grenada substation is located in Ann Arbor. There are four substations serving the general area: Grenada, Price, Prospect and Wolverine. Safety: 4.8kv areas of Pospect: 4.8kV wire down elimination Reliability: GRENA has a 3-year average SAIDI of 1,487 Capacity: Substations over firm rating. Circuits over distribution design order. There is continued load growth in the area and the existing substations and circuits are unable to support Ann Arbor's electrification goals. Operability: There is a lack of jumpering capability for Grenada, Prospect and Price substations. The use of distributed generation would be required in the case of any failure at the substations mentioned above. Failure can lead to customer outages/stranded load.
Lark/Spruce	Ann Arbor	Safety: Spruce substation (SPRUC) has equipment that has been designated as high risk. It will be easier to replace this equipment once the substation expansion is completed at LARK (120-40kV ITC/DTE Station in proximity of Spruce). Reliability: Spruce circuits have frequent outages that have resulted in higher than system average SAIDI and CAIDI minutes. There are sections of circuits that are located in difficult to access areas which are problem areas for downed wires. Capacity: Spruce substation loading is over its firm rating. There are circuits that have exceeded the Distribution Design Order (DDO) limit for 13.2kV loading with other circuits approaching that limit in the near future. There is limited capacity for load growth in the area. Operability: Spruce circuits have areas that are 13.2kV islands (adjacent to 4.8kV) which has led to limited jumpering points and little opportunity for load transfers.
Jewell	Washington Twp	Reliability: The largest causes of outages is due to trees and equipment break. The circuits have been close to and have gone over the DTE average for SAIDI/CAIDI. Capacity: Substation over firm rating. Multiple circuits over and approaching day to day rating. Multiple circuits exceed distribution design order. There is load growth and new business across the Jewell Substation area. Operability: little to no load transfers available. Failure can lead to customer outages/stranded load. Other: There has been several residential developments happening on JEWEL within the past couple years. JEWEL area has a lot of open land so we can expect for more businesses and residential developments to come.
Mayville	Mayville, Clifford	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: The area has suffered from extensive outage events that lead to a large amount of stranded load for more than 24 hours. Capacity: Substations over firm rating. Circuit over day to day rating. Circuits over distribution design order limit.
Goodison	Oakland Twp	Reliability: GODSN SAIDI and SAIFI usually is above the DTE system average. Issues from TIE line cause outages to the substation, especially in 2023. Capacity: GODSN is at 129% of its firm rating. Both GODSN circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Operability: Jumpering options outside of GODSN are not available during summer peak due to TINKN and JEWEL substations exceeding their firm ratings and because of the heavy loading on neighboring circuits. Overloads and low voltage occur when load is jumpered over to neighboring substation.

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1 Table 10 System Loading Projects, Continued

Project Name	Municipality	Drivers
Wixom	Wixom	Safety: Existing PDC and TRF1 are in close proximity, which is a fire hazard and is a worker safety hazard. In addition to the loading concerns at the substation, the existing switchgear at the substation is reaching its end of life and the breakers are at an elevated risk due to interruption medium. Reliability: SAIDI fluctuates year after year for WIXOM circuits and a few circuits exceed DTE system average. Most outages occur during storm. Capacity: Substation over firm rating. Circuits over distribution design order. Circuits above nominal cable day to day ratings. Operability: When a substation transformer fails, then at least (2) diesel generators are needed to support load at summer peak. There are only (2) jumpering points outside of Wixom substation at summer peak. Other: Receiving multiple method of services (customer load requests). WIXOM cannot support industrial customers due to existing circuit loadings. Wixom is the fastest growing city in Michigan.
Diamond	Dexter	Diamond substation is a two transformer, four circuit substation and is at 137% of its firm rating. Reliability: In summer 2018, load shedding was implemented at the substation due to equipment overloads. SAIFI 5 year average is 1.97 and SAIDI 5 year average is 566. Capacity: Two of the four circuits exceed the distribution design order standard of 8MVA for a 13.2kV circuit. The substation is currently at 137% of firm rating. Operability: Transformer #1 was replaced during an emergency failure event in March 2019; firm rating is now limited by smaller sized transformer #2.
Spokane/Seneca	Rochester Hills	Safety: Substation flooding due to the lack of a drainage system at Spokane substation has damaged the conduit system by causing it to cave in. This has impeded the use of the 9-position switchgear and the associated third transformer at the site. Capacity: Substations over firm rating. Circuits exceed distribution design orders of 8MVA per circuit. Operability: Limited jumpering options outside of Spokane substation due to overloads at adjacent Seneca and Tienken substations. Failure can lead to customer outages/stranded load. Other: DTE's Equipment Performance and Protective Maintenance group recommends the replacement of the current 11-position switchgear, as it is at risk of failure.
Sterling	Sterling Heights, Macomb County	Capacity: Circuit approaching day to day limit. Circuits exceed distribution design order limit. There is evidence of re-development and steady growth still coming into the Substation area. Load cannot be transferred to adjacent circuits without causing similar loading issues. There are no positions available at Sterling Substation to create new circuits to provide relief and additional capacity. Other: The current switchgear at Sterling substation is not the standard DTE setup. It is a straight bus switchgear which is exposed to a single point of failure.
Disco	Sterling Heights	Safety: There is a high chance of wire downs in the area due to DISCO OH lines being surrounded by many trees. The main cause of wire downs in the area are caused by winds and trees. A portion of DISCO OH lines are also truck inaccessible. Reliability: DISCO circuits currently have limited jumpering options due to the neighboring circuits being over loaded. In 2022 the SAIDI and CAIDI for all DISCO circuits were above the DTE system average due to several day outages. Trees and wind were the main causes for the outages. Capacity: Substation over firm rating. Circuits over distribution design order. Operability: DISCO circuits have limited jumpering options due to neighboring circuits being overloaded. Failure can lead to customer outages/stranded load.
Tahoe	Novi	Capacity: Tahoe substation is over its firm rating. Since Novi Substation is being decommissioned and the load is being transferred to Tahoe, peak loads at TAHOE DC 8928 and TAHOE DC 9512 will exceed the distribution design order standard of 8.0 MVA for a 13.2kV circuit. TAHOE DC 9511 is also approaching the Distribution Design Order limit. Operability: Current loading conditions inhibit the creation of jumpering points and installation of loop schemes in the area.

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Table 10 System Loading Projects, Continued

Project Name	Municipality	Drivers
New Baltimore / Chesterfield	Chesterfield/ New Baltimore	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: NBALT is over its blocking limit to protect TRK4911 and a loss of transformer 3 will result in 3MVA of stranded load. Capacity: Substations over firm rating. Circuits over day to day rating. Circuits over distribution design order limit. Operability: Limited jumpering options available. Failure can lead to customer outages/stranded load. Other: There have been three Method of Service requests since January 2021 totaling 2.3MVA load increase at NBALT substation. There have been 6 Method of Service requests since January 2021 bring 2.24MVA of load to CHEST substation.
Kings Point	Clinton Township and Mount Clemens, Macomb Twp	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: Substation over firm rating. Circuits over day to day rating. Circuits over distribution design order. Nearby Omega substation is a 40kV-13.2kV substation which is 5.4MVA of its blocking limit. The loss of either transformer at Omega substation results in 5.8MA of stranded load. The subtransmission lines are overloaded in the area (Trunk 7909 and Trunk 6759). The current infrastructure is unable to support new load growth in the area. Operability: Omega and surrounding substations high loading limits jumpering options. Failure can lead to customer outages/stranded load.

Q88. What are the benefits of System Loading projects?

A88. System Loading projects alleviate the stress on the system caused by overloads and reduce potential failures. These projects increase capacity and reconfigure the system to eliminate projected overloads on specific pieces of equipment (overhead wire, underground cable, transformers), or at the circuit/substation level. While each project may add a different amount of new capacity, following completion of a system loading project, substations shall be under 100% of firm rating, and all equipment shall be under 100% of day-day rating. Capital investment to address these system overloads will also improve reliability and provide capacity for new and existing customers. Additionally, system loading projects help maintain/improve system operability by restoring/creating jumpering capabilities and removing aged equipment from the system.

The best way to demonstrate the benefits of System Loading projects is to use an example. The Grenada project will deliver on system loading, conversions, and automation benefits. The first step of the project is to rebuild and convert a portion of an adjacent Prospect circuit which will deliver improved reliability from the rebuilds, but also mitigate an overload at Prospect substation which is currently over 100% of firm rating. Construction of a new Grenada substation will increase capacity by 77% versus the existing Grenada substation, providing capacity for continued growth and mitigating circuit overloads. Finally, additional conversions will enable installation of loop schemes and circuit automation; none of which are possible without the capacity delivered in the system loading project. When fully implemented, the project is anticipated to deliver an 88% improvement in reliability versus three-year historic SAIDI for the area.

Even though each of the projects in the System Loading program are designed to address the concerns/issues for a particular part of the grid, they have similar benefits in the range of what was discussed for Grenada.

Q89. What is the scope of work for System Loading projects?

A89. System Loading projects include scope to add capacity to the distribution system, and typically include:

- Acquisition of land for new substations, if necessary
- Construction of new substations
- Expansion of current substations by installing additional transformers
- Replacing existing transformers
- Installing new switchgear lineups

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- Creating new distribution circuits
- Reconductoring circuits (overhead wire and/or underground cable)
- Converting circuits to higher voltage, where necessary and transferring load once additional capacity has been created

Many areas identified in the priority ranking for system load relief are addressed as part of CODI, 4.8 kV Conversion, or 8.3 kV Pontiac Conversion programs. Load relief needs excluded from conversion programs are included in the System Loading projects category.

Q90. How are system loading projects prioritized?

A90. Distribution engineers assess the load on the system and its impact on individual pieces of equipment under two conditions: normal state and contingency state. This analysis determines if adequate distribution system capacity exists to serve both current and projected future demands.

System loading information from this analysis is updated and evaluated annually. Projects are evaluated for load relief on how they address five factors: substation equipment overload, substation over firm rating, circuit equipment overload, strong load growth or circuits over 8 MVA for 13.2 kV circuits and 3 MVA for 4.8 kV. Based on these variables a priority ranking of the load relief projects is developed. More information about Load Relief criteria and prioritization can be found in Section 9.1 of the DGP (Exhibit A-23 Schedule M8 sponsored by Witness Kryscynski).

Q91. Can you summarize the key themes of your testimony?

A91. Yes. Projects in Infrastructure Redesign and Modernization pillar are a key part of the Company's plan for the grid of the future and fundamentally change the way the grid operates. These projects add capacity by converting the distribution system to a higher voltage for growing customer load, reduce outages and shorten outage restoration time by incorporating modern technology and equipment, hardening the grid, improve redundancy and resiliency of the system, and increase safety. IRM treatment of these types of investments can benefit customers by ensuring that projects are deployed where they are needed most.

The projects in this pillar are vital to support the continued resurgence of the city of Detroit and to provide the needed energy to ensure a bright future for Michigan.

Q92. Does this complete your direct testimony?

A92. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MORGAN ELLIOTT ANDAHAZY

QUALIFICATIONS AND DIRECT TESTIMONY OF MORGAN ELLIOTT ANDAHAZY

Line No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name is Morgan Elliott Andahazy (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. Please state your educational background.

A3. I hold a Bachelor of Science in Engineering (Industrial and Operations Engineering) and a Master of Business Administration, both from the University of Michigan, Ann Arbor.

Q4. Do you have any professional certifications or other certificates?

A4. I received my Lean Six Sigma Black Belt certification in 2009.

Q5. Please summarize your work experience.

A5. In 2007, I joined DTE Electric as a contract employee supporting the Distribution Operations Continuous Improvement (DOCI) team. In March 2008, I joined DTE Electric as a full-time employee and a Project Lead within the DOCI team. As a Project Lead, I was responsible for measuring and improving productivity within the Electric Field Operations (EFO) organization. During this time, I obtained my Lean Six Sigma Black Belt certification based on work I did with EFO Productivity projects. In 2009, I transitioned to the Continuous Improvement (CI) Manager for Distribution

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Operations (DO) where I was responsible for the team of Project Leads supporting improvement projects throughout DO. In March 2010, I moved to a new developmental assignment as a Field Supervisor for the Underground (UG) Cable Pulling team at the Trombly Service Center. At Trombly, I was responsible for overseeing the daily construction work performed by the UG Cable Pullers and supervising a Union-represented workforce. In January 2011, I was promoted to the CI Manager for Corporate Services. I was responsible for coordination and implementation of CI training within the organization, and I led the team of CI experts responsible for improvement projects. In October 2011, I transitioned to Manager, Trombly Service Center, where I was responsible for all UG operations (cable pulling and cable splicing) for the Southeast (SE) Region of DO. In April 2013, my role expanded to Manager, SE Region, which consisted of three service centers (Trombly, Redford, and Caniff) and included all Overhead (OH) and UG operations in the SE Region. In March 2016, I was promoted to Director, Service Operations responsible for all OH and UG operations in Southwest (SW), Northwest (NW), and Northeast (NE) regions in DO. In this role, I also assisted in Local 17 contract negotiations. In October 2017, I assumed the position of Director, Advanced Distribution Management System (ADMS). I lead the team responsible for the successful implementation of the new ADMS. This team was responsible for the strategic direction, vendor selection, and implementation of all ADMS components including the Generation Management System (GMS), Energy Management System (EMS), Outage Management System (OMS), Distribution Management System (DMS), and the Network Management System (NMS). In April 2022, I transitioned to the Director, Project Management Organization (PMO) within Electric Distribution Operations (DO). In this role, I led the team that was responsible for managing the execution of all strategic capital programs and projects. As of July 2023, my role has shifted to the management of only the strategic capital programs.

Q6. What are your current duties and responsibilities?

A6. As Director – PMO Programs, I lead the team that is responsible for managing the execution of the programs making up the majority of the Infrastructure Resilience and Hardening strategic investment discussed in my direct testimony. My team consists of the project managers, project coordinators, construction/field supervisors, engineers, and the leadership/support teams required to manage and track the progress of our investments.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

U-20836 2022 DTE Electric Rate Case

U-21297 2023 DTE Electric Rate Case

Purpose of Testimony

Q8. What is the purpose of your testimony in this proceeding?

A8. The purpose of my testimony is to support, as reasonable, prudent and necessary, the historical capital expenditures for 2022 and projected capital expenditures for 2023 through December 31, 2025, in the distribution strategic capital category of Infrastructure Resilience and Hardening.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plant (Pages 1, 2, 13, 19-26)
A-12	B5.4.8	4.8kV Hardening and Pole & Pole Tope Maintenance and Modernization (PTMM) – Details
A-23	M5	Distribution Plant Capital Project Detail – The Infrastructure Resilience and Hardening Pillar
A-23	M9	Wood Pole Maintenance Specification
A-23	M10	Pole Top Maintenance Specification
A-23	M12	4.8kV Hardening Technical Conference
A-23	M13	PTMM Benefit Cost Analysis Whitepaper

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I: The Infrastructure Recovery Mechanism

Part II: The Infrastructure Resilience and Hardening Pillar

<u>Part I: The Infrastructure Recovery Mechanism (IRM)</u>

Q12. Are any of the programs you are supporting impacted by the Company's Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM)?

A12. Yes, as described by Company Witness Foley in his testimony, in its December 1, 2023 Order in Case No. U-21297 (December 2023 Order) the Commission authorized IRM treatment for the Breaker Replacement Program and the URD Replacement Program. IRM treatment was authorized starting on December 1, 2023, and running through the end of 2025.

Q13. Is the Company proposing any investment in these programs during the bridge and/or test years beyond what the Commission previously authorized for recovery through the IRM?

A13. Yes, as reflected in Exhibit A-12, Schedule B5.4, Page 13, Lines 16 and 18, the Company is proposing recovery of investment in these programs made in 2023 prior to the IRM being authorized by the Commission in its December 2023 Order. All bridge and test year investments in these programs after the IRM was authorized is being recovered through the IRM. As such, 2024 investment (column d) and 2025 investment (columns e and g) are $0 in the exhibit, reflecting no recovery is being proposed through base rates for these programs in those years.

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Q14. Is the Company proposing recovery for any additional investment in these programs through the IRM beyond the test year of this case?

A14. Yes, as described by Company Witness Foley, the Company is proposing a two-year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that extension the Company is proposing recovery of additional Breaker Replacement Program investment and URD Replacement Program investment as captured in Exhibit A-33, Schedule X1, Lines 4 and 5.

Q15. Is the Company proposing any additional programs be authorized for IRM treatment beyond the test year of this case?

A15. Yes, as part of the proposed two-year IRM extension described by Company Witness Foley, the Company is proposing that the Pole and Pole Top Maintenance & Modernization (PTMM) program be authorized for IRM treatment. The Company is proposing $150 million of capital investment in 2026 and $200 million of capital investment in 2027 for this program, as captured in Exhibit A-33, Schedule X1, Line 7.

Q16. Why is the Pole and Pole Top Maintenance & Modernization (PTMM) program a good candidate for IRM treatment?

A16. There are three screening criteria that the Company used to identify the capital programs it proposed to be authorized for IRM treatment. Specifically, the Company looked for programs that had the following characteristics:

- Critical to customer safety, reliability, and/or resiliency
- Sufficient size and duration
- Well-understood scope

The Company believes that the PTMM program meets these criteria and therefore is a good candidate to be authorized for IRM treatment.

<u>Part II: The Infrastructure Resilience and Hardening Pillar</u>

Q17. What is the Infrastructure Resilience and Hardening Pillar?

A17. The Infrastructure Resilience and Hardening Pillar includes programs and projects focused on near-term grid infrastructure investments to harden the system against an increasing frequency and severity of high winds and storms[1], address frequent outage circuits, and replace damaged and/or defective infrastructure. These investments support employee and public safety, customer reliability, and reduce risk to the grid.

Capital investment details of programs and projects in this category are included in the following:

- Exhibit A-12, Schedule B5.4, page 13 – Infrastructure Resilience and Hardening Capital Investments;
- Exhibit A-12, Schedule B5.4.8 – 4.8kV Hardening Program and PTMM Program Details;
- Exhibit A-23, Schedule M5 – Infrastructure Resilience and Hardening Program and Project Charters; and
- Exhibit A-12, Schedule B5.4 includes AFUDC for this category on page 19 and plant activity on pages 20 and 21, described in more detail by Company Witness Kryscynski.

[1] The severity of recent storm activity is discussed by Company Witness Hill beginning on page BLH-9.

Q18. What programs and projects fall under the Infrastructure Resilience and Hardening Pillar?

A18. The Infrastructure Resilience and Hardening Pillar consists of the following programs and projects:

- 4.8kV Hardening Program
- Pole and Pole-Top Maintenance and Modernization (PTMM) Program
- Substation Risk Projects
- Frequent Outage Programs (CEMI[2])
- Cable Replacement Program (System Cable)
- Underground Residential Distribution (URD) Replacement Program
- Breaker Replacement Program
- Mobile Fleet Program
- Pontiac Vaults Projects
- 40kV: Automatic Pole Top Switch Program
- Disconnect and Switcher Replacement Program
- Steel Pole Highway Crossings Program
- Batteries and Chargers Replacement Program
- SCADA Pole Top Device Replacement
- Substation Regulator Replacement
- Portable Generators Program

<u>The 4.8kV Hardening Program</u>

Q19. Why was the 4.8kV Hardening Program created?

[2] Customers Experiencing Multiple Interruptions (CEMI) is an industry term that is often used interchangeably with frequent outages.

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A19. The 4.8kV Hardening Program was developed in 2017 to be a near-term, cost-effective way to improve public safety and reliability in and around the City of Detroit. The program improves safety by removing Detroit Public Lightning Department (DPLD) arc wire where it is co-located with DTE equipment and is therefore at risk of becoming energized. The program improves reliability by replacing damaged poles and pole-top equipment in locations that contain some of the oldest infrastructure in DTEE's service territory. The 4.8kV Hardening Program allows for a more rapid removal of arc wire alongside improved reliability and safety, ahead of the longer-term circuit conversions that will ultimately replace 4.8kV infrastructure.

Q20. What is the scope of the 4.8kV Hardening Program?

A20. The scope of the 4.8kV Hardening Program includes all overhead circuits in and around the city of Detroit in areas known to contain DPLD arc wire.

The program's work activities are listed below:

- Test all utility poles that have Company equipment attached and replace or reinforce those poles as needed.
- Trim trees, as required, to support construction activities.
- Remove DPLD arc wire from Company-owned equipment; ensure the remaining Company wires are left in a safe configuration.
- Remove DPLD distribution wire from Company-owned equipment when it can be confirmed that the wire is not serving customers.
- Replace wooden crossarms with fiberglass crossarms as needed.
- Replace other pole-top equipment as required, allowing for rebalancing of the remaining conductor.

- Remove service lines to abandoned properties.
- Remove primary conductor in sparsely populated areas (primary deconductoring).
- Perform any additional work necessary as dictated by field conditions.

Figures 1 and 2 show examples of before and after the 4.8kV Hardening work activities are completed.

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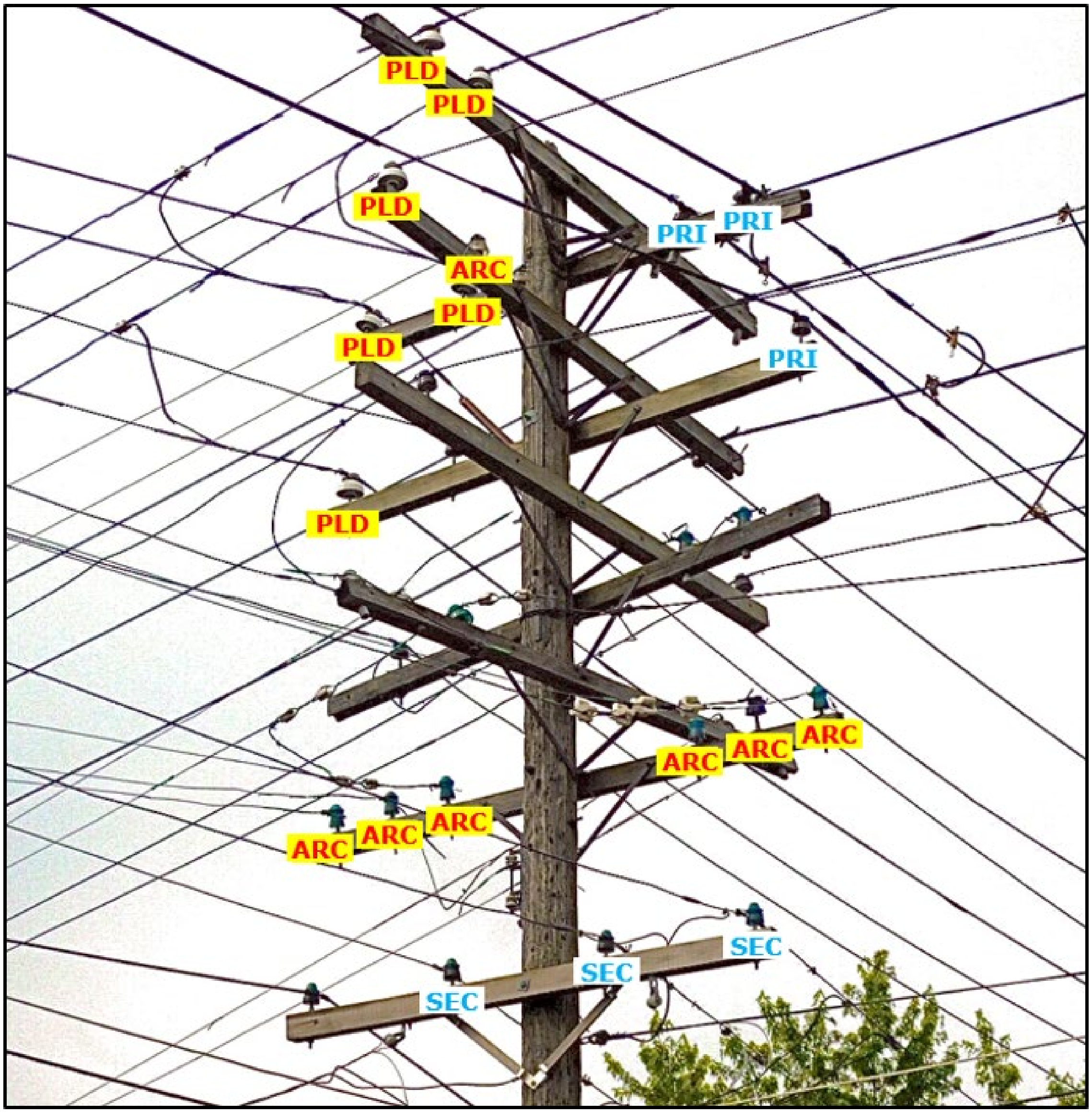
Figure 1. Before Hardening – Example



PLD: DPLD Distribution Wire

ARC: DPLD Arc Wire

PRI: DTEE Primary Wire

SEC: DTEE Secondary Wire

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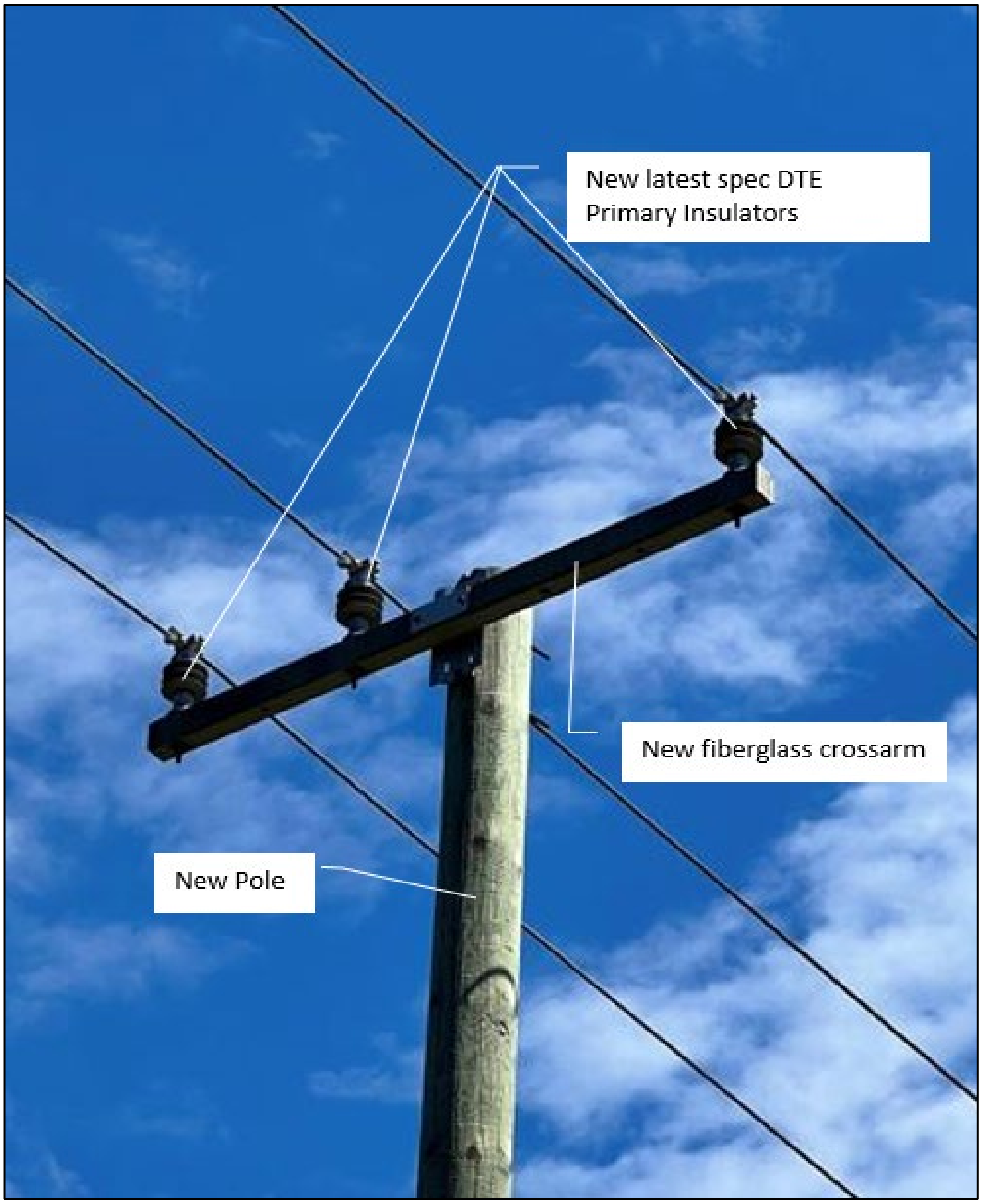
Figure 2. After Hardening – Example



Q21. Why does the 4.8kV Hardening Program include tree trimming and pole and pole-top equipment replacement rather than only removing DPLD arc wire?

A21. These additional activities beyond removing DPLD arc wire are necessary to make the worksite accessible for field crews, and safe for both field crews and the public. Tree trimming is necessary for field crews to gain access to the poles as well as the wire.

Testing and replacing or reinforcing poles is necessary to make the site safe and supports improved resiliency and reliability. Crossarm replacement and rebalancing is likewise necessary, as removing the DPLD arc wire only could potentially leave crossarms dangerously unbalanced and create hazards. Unbalanced crossarms may occur because DPLD arc wire and the Company's overhead lines were originally installed to provide equal force on each side of the crossarm; when the arc wire is removed, the remaining DTE wires exert force on only one side of the crossarm, resulting in the need for the wires to be rebalanced so they are properly supported.

Q22. Has the Commission previously supported the Company's investments in the 4.8kV Hardening Program?

A22. Yes. The Commission approved 4.8kV Hardening Program investments in Case Nos. U-20162, U-20561, U-20836, and U-21297. The 4.8kV Hardening Program aligns with the Commission's expectation that the Company remove DPLD arc wire[3].

The Commission has since reiterated its support for the 4.8kV Hardening Program in Case No. U-21297 stating:

> Completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the removal of the arc wire should be going faster. While the work is expensive (in part because hardening means going back to the same pole twice), comprehensively addressing the safety and equity concerns is a priority and the Commission recognizes that

[3] In its September 28, 2018 Order in Case No. U-18484 the Commission noted that "[a]ppropriate integration of arc wire removal with other DTE Electric programs, such as the hardening and conversion programs, is a crucial aspect of planning and executing strategies." (U-18484 Order, pg. 6)

conversion takes much longer than hardening. … the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire as discussed by the Staff. (U-21297 - Commission Order, December 1, 2023, p. 93-94)

Q23. What stakeholder engagements for the 4.8kV Hardening Program were required by the Commission in Order No. U-20836?

A23. The Company was directed to hold stakeholder engagements in the first quarter of 2023 covering the following items:

- Complete a full analysis that demonstrates the specific costs of hardening, conversion, distributed energy resources (DERs), tree trimming, and/or other alternatives compared with the benefits, such as improving safety and reducing System Average Interruption Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).
- Conduct an analysis of the capabilities/constraints of the 4.8kV system and how it affects the use of DERs and electric vehicles (EVs) compared to conversion to a 13.2kV system.
- Complete a full analysis and comparison of alternatives to hardening including use of DERs and EVs compared to conversion to a 13.2kV system.
- Complete a full analysis of optimal reliability-focused distribution technologies and plan a course of action for arriving at an equitable future for environmental justice and other disadvantaged communities.
- Calculate the miles of arc wire removed to date, the estimated miles of arc wire remaining, the level of confidence that all arc wire is captured in the Company's

inventory, the cost of removal with the 4.8kV hardening program, and the cost without the program.

Q24. Did the Company perform the alternatives analysis and host the Technical Conference in Q1 2023?

A24. Yes, the Company presented an overview of its distribution system and alternatives to the 4.8kV Hardening Program at the DTE Electric 4.8kV Technical Conference hosted by the MPSC Staff on March 22, 2023. This presentation can be found in Exhibit A-23, Schedule M12 - 4.8kV Hardening Technical Conference.

Q25. What was presented to the MPSC Staff and Intervenors regarding the 4.8kV Hardening Program in the March 22, 2023, Technical Conference?

A25. The Company presented the following:

- An overview of the 4.8kV distribution system,
- A comparison of the 4.8kV and 13.2kV distribution systems,
- A list of considerations for the implementation of electric vehicles and distributed energy resources,
- An overview of the City of Detroit and DPLD arc wire infrastructure,
- A description of the program scope and customer benefits of the 4.8kV Hardening Program, and
- A discussion of alternatives to the 4.8kV Hardening Program.

The March 22, 2023, Technical Conference materials (including the agenda, presentation slides, video recording of the meeting, and follow-up questions and answers) can be found at https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference.

Q26. What alternatives were considered to the 4.8kV Hardening Program?

A26. Four alternatives were considered: arc wire removal, pre-conversion, conversion, and microgrids, and their associated required investment, execution complexity, and anticipated customers benefits (Table 1).

Arc Wire Removal includes trimming trees as necessary, reinforcing/replacing poles and replacing pole top equipment as necessary, removing DPLD arc wire, and rebalancing cross arms.

Pre-conversion includes trimming trees as necessary, rebuilding pole tops, replacing poles and transformers as necessary, removing DPLD arc wire, reconductoring overhead lines as needed, installing neutral wire, and rebuilding underground infrastructure as necessary.

Conversion includes all pre-conversion activities as well as substation expansions as necessary, new substation construction as necessary, new circuit construction, circuit reconfiguration, and load transfer work activities.

Microgrids includes all pre-conversion activities as well as solar and battery storage installation, support equipment installation (inverters, switchboards, communication gateways, reclosers, etc.), and site preparation needed to house this equipment.

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Table 1. Hardening Program Alternatives Overview

Selected for Consideration

Increasing difficulty

		Arc Wire Removal	Improved Reliability	Improved Safety/ Wire down	Improved Capacity	Cost Level	Execution Complexity
	Tree Trimming	○	◑	◔	○	Low	Low
	PTMM	○	◑	◔	○	Low	Low
1	Arc Wire Removal	●	◔	◔	○	Medium	Low
2	4.8kV Hardening	●	◕	◑	○	Medium	Low
3	Pre-conversion	●	●	●	◔	High	Medium
4	Conversion	●	●	●	●	High	High
5	Micrograds	●	●	●	◑	Very High	Very High
	DERs	○	○	○	◔	Medium	Medium
	Energy Efficiency	○	○	○	◔	Low	Medium
	Storage	○	◔	○	◑	High	Medium

Q27. How does the 4.8kV Hardening Program compare to these alternatives in terms of investment required and expected benefits?

A27. The Company presented Table 2 during the March 22, 2023, Technical Conference. This table shows the average investment required per mile, expected wire-down reduction, SAIFI[4] reduction, CAIDI[5] reduction, capacity impact, DER[6] support, and execution complexity for the 4.8kV Hardening Program and its alternatives.

[4] System Average Interruption Frequency Index (SAIFI) is an industry term and is the measurement of the average frequency of outage events any given customer on the Company's system would experience.
[5] Customer Average Duration Interruption Index (CAIDI) is an industry term is a measurement of the average outage duration that any given customer on the Company's system would experience. CAIDI is the average outage restoration time for a customer outage.
[6] Distributed Energy Resources (DER) are devices such as electric vehicle chargers and customer-owned solar panels.

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Table 2. Hardening Program Alternatives Comparison

	Avg. Cost per Mile ($ thousands)	Wire down Reduction	SAIFI Reduction	CAIDI Reduction	Capacity Increase	Increased DER Usage	Execution Complexity	Potential Use Case
Arc Wire Removal	$191	13%	22%	36%	No	No	Low	Lowest overall cost to remove arc wire
4.8kV Hardening	$353	26%	44%	72%	No	No	Low	Highest benefit/cost for reliability improvement
Pre-conversion	$1,700	90%	85%	85%	No	Yes	Medium	Provides step change in reliability performance
Conversion	$2,700	90%	85%	85%	Yes	Yes	High	Best benefit/cost for significant capacity needs
Microgrids	$14,600	90%	95%	95%	Yes	Yes	Very High	Potentially application for grid areas with critical reliability needs

The 4.8kV Hardening Program strikes the best balance of removing DPLD arc wire in the near-term while also offering significant reliability improvements and being affordable for customers.

Q28. In addition to the analysis presented in the Technical Conference, what additional analyses for the 4.8kV Hardening Program were required in Order for Case No. U-21297 on December 1, 2023?

A28. The Commission ordered the Company to:

- Create a comprehensive, detailed, and longer-term plan for this work that includes an equity and safety analysis. The equity analysis must meet the following requirements include EJ analyses that provide community vulnerability gradations based on the MiEJScreen tool using 0% to 5%, 5% to

10%, and 5% gradations all the way to 95%-100% of the MiEJScreen composite score;

- Identify and qualify the potential hazard associated with other DPLD wire for which DTE Electric has not provided documentation to date; and
- Show how equity has informed, and continues to inform, the Company's actions with respect to 4.8kV Hardening and arc wire removal efforts.

Q29. Has the Company completed the Environmental Justice (EJ) analyses as directed by the Commission pertaining to the 4.8kV Hardening Program?

A29. Yes. The Company has performed an EJ/equity analysis of the 4.8kV Hardening Program by mapping its circuits to census tracts and cross-referencing with the MiEJScreen tool. The MiEJScreen tool can be found at https://www.michigan.gov/egle/maps-data/miejscreen.

As shown in Company Witness Kryscynski's testimony, 85% of all 4.8kV Hardening Program investments from 2018-2025 impact communities that score between the top 80-100% MiEJ scores and are deemed vulnerable. More details of EJ/equity analysis can be found in Company Witness Kryscynski's testimony.

Q30. What progress has been made through year-end 2023 on the 4.8kV Hardening Program?

A30. The Company hardened approximately 373 miles in 2023 (Table 3) and has hardened nearly 1,500 miles total from 2018-2023, which represents approximately 70% of the total program scope. The Company has removed approximately 208 miles of arc wire in 2023, and approximately 640 miles total from 2018-2023.

A total of 307 circuits, representing approximately 196,000 customers in the city of Detroit and surrounding areas, have been hardened by the program through year-end 2023.

Table 3. 4.8kV Miles and Arc Wire Removed through 2023

4.8kV Hardening	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	Total
Miles Hardened	105	128	209	202	475	373	**1,492**
Arc Wire Miles	59	52	105	64	155	208	**643**
Capital Investment ($ thousands)	$40,325	$48,278	$55,165	$65,362	$157,482	$127,010	

Q31. Why are there fewer miles of DPLD arc wire removed than miles hardened in each year of the 4.8kV Hardening Program?

A31. There are fewer miles of DPLD arc wire removed because the DPLD system does not perfectly overlap DTE's distribution system. The Company has observed that there is, on average, approximately twice as much DTE distribution wire on Detroit circuits as there is DPLD arc wire.

Q32. Does the 4.8kV Hardening Program target areas that do not contain DPLD arc wire?

A32. No. The 4.8kV Hardening Program does not target areas that do not contain DPLD arc wire. The program targets all circuits on substations in areas known to contain DPLD arc wire. However, it is often the case that a circuit does not contain as much DPLD arc wire as DTE distribution wire. Because there is a fixed cost to planning work and mobilizing and demobilizing crews, the Company hardens the entire circuit so that all customers in the area benefit from improved safety and reliability.

Q33. What is the Company's plan to accelerate and complete the 4.8kV Hardening Program?

A33. The 2024 4.8kV Hardening workplan includes the hardening of approximately 145 circuit miles and removing 95 miles of arc wire. The Company has accelerated its plans for removing arc wire in response to the direction provided by the Commission[7]. The 2025 4.8kV Hardening workplan includes hardening approximately 310 circuit miles and removing 189 miles of arc wire. The 2026 4.8kV Hardening workplan includes hardening approximately 116 circuit miles and removing 89 miles of arc wire. Table 4 shows the total planned circuit miles hardened and DPLD arc wire removed at the conclusion of the 4.8kV Hardening Program in 2026.

A total of approximately 500 circuits, representing approximately 295,000 customers in the city of Detroit and surrounding areas, will have been hardened at the conclusion of the program.

[7] In its December 1 Order in Case No. U-21297 the Commission stated, "completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the removal of the arc wire should be going faster." (Order at pg. 93)

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Table 4. Miles Hardened and DPLD Arc Wire Removed

4.8kV Hardening	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Miles Hardened	105	128	209	202	475	373	145	310	116	**2,063**
Arc Wire Miles	59	52	105	64	155	208	95	189	89	**1,015**
Capital Investment ($ thousands)	$40,325	$48,278	$55,165	$65,362	$157,482	$127,010	$80,000	$125,000	$35,960	

Q34. At the conclusion of 2026, how much of the DPLD arc wire that is co-located with DTE equipment will be removed and how much will be remaining?

A34. The Company had patrols conducted on its infrastructure in and around the City of Detroit, and the final combined total of co-located DPLD arc wire identified was approximately 1,268 miles (Table 5).

Table 5. DPLD Arc Wire Removal 2018-2026

Program	Arc Wire Miles
4.8kV Hardening	1,015
Remaining DPLD Arc Wire	253
Total	**1,268**

The Company estimates that approximately 1,015 of these DPLD arc wire miles will be removed by the 4.8kV Hardening Program from 2018-2026 and that 253 miles of DPLD arc wire will be remaining. The Company is continuing to evaluate its plans for removing the remaining DPLD arc wire with the remaining miles being addressed with circuit conversion projects, and the possibility of further 4.8kV Hardening work to ensure timely removal.

Q35. Has the Company patrolled and catalogued all DPLD arc wire beyond that which is co-located with Company infrastructure?

A35. No. The Company has only patrolled and identified DPLD arc wire that is co-located with Company equipment. The Company focused on cataloging co-located DPLD arc wire because it represents a safety risk due its close proximity to energized wire and has the potential to become energized as explained in Question 20.

Q36. How does the 4.8kV Hardening Program benefit customers?

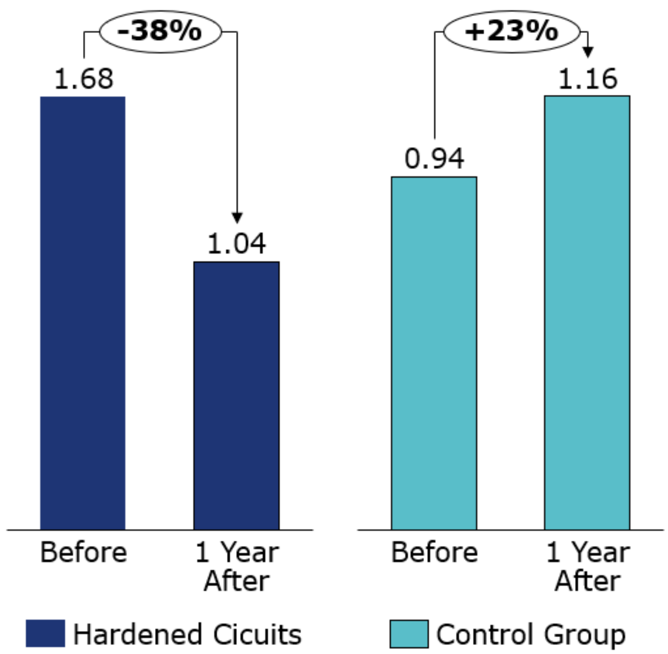
A36. Results show that the 4.8kV Hardening Program has been effective in improving the safety, reliability, and resiliency of circuits (Figures 3, 4, and 5).

The Company reviewed the three-year historic average for reliability and wire-downs of the circuits hardened prior to the year hardened, and compared those numbers to the year after hardening was complete. The Company also reviewed the three-year historic average for reliability and wire-downs for circuits in the control group (which includes the city of Detroit, and surrounding areas), that were not hardened in that time period. The circuits included in this analysis were hardened in 2019, 2020, and 2021. Three key metrics were reviewed to determine the effectiveness of the 4.8kV Hardening Program: All-Weather System Average Interruption Frequency Index (SAIFI), System

Average Interruption Duration Index (SAIDI) excluding major event days (Ex-MED[8]s), and Wire-Downs.

All-Weather SAIFI reflects the frequency of the outage events experienced by customers on the circuits regardless of weather conditions. SAIDI Ex-MEDs is an indicator of the amount of time customers are without power excluding the most significant weather event days, such as very large storms. The reduction in the number of wire-downs is a measure of the safety improvements for the circuits that were hardened.

Figure 3. 4.8kV Hardening All-Weather SAIFI



[8] Major Event Days (MEDs) is an industry term that denotes a day in which a utility experienced a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period. More information about MEDs and their calculation can be found at https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2003-01-Major-Events-Classification-v3.pdf.

Figure 3 displays the All-Weather SAIFI improvement of hardened circuits vs. the control group; the customers on hardened circuits experienced a 38% improvement in All-Weather SAIFI, while the control group circuits degraded by 23%, resulting in a net improvement of 61% for hardened circuits.

Figure 4. 4.8kV Hardening SAIDI excluding MEDs

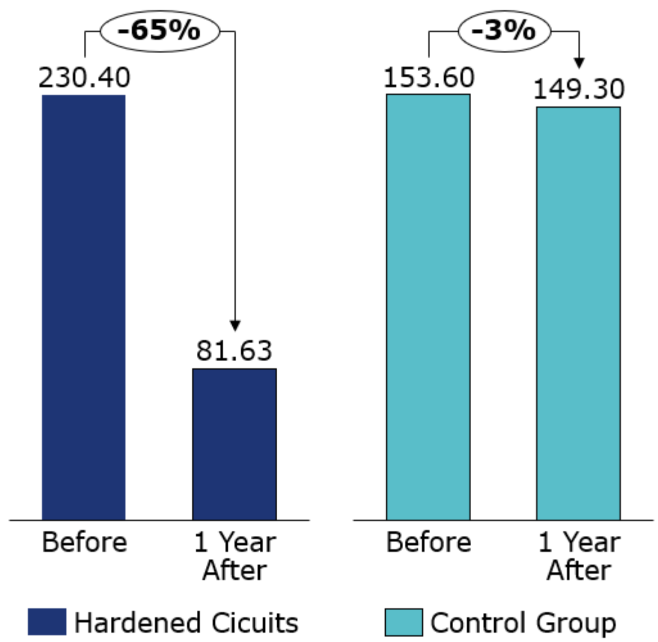


Figure 4 displays the SAIDI Ex-MEDs improvement of hardened circuits vs. the control group; the customers on hardened circuits experienced a 65% improvement in SAIDI Ex-MEDs, while the control group improved by 3% improvement, resulting in a net improvement of 62% for hardened circuits.

Figure 5. 4.8kV Hardening Wire-downs

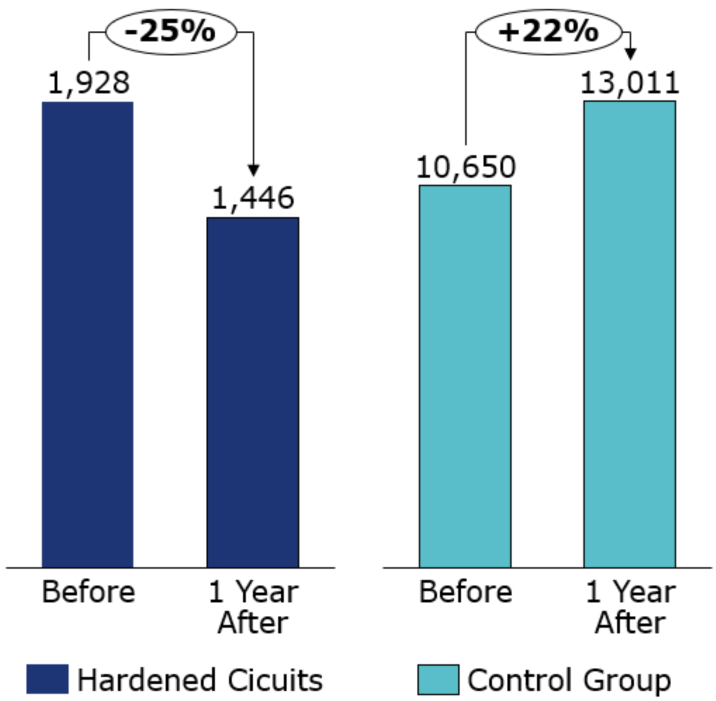


Figure 5 displays the wire-down event improvement of hardened circuits vs. the control group; the customers on hardened circuits demonstrated a 25% improvement, while the control group degraded by 22%, resulting in a net improvement of 47% for hardened circuits.

Q37. Why does the 4.8kV Hardening Program perform deconductoring on some circuits?

A37. As stated in Company Witness Deol's testimony, the customer benefits of deconductoring are the elimination of potential wire-downs by removing overhead lines that are not fully utilized and the elimination of potential power outages caused by those lines failing or being damaged. The primary drivers of the 4.8kV Hardening Program are to remove DPLD arc wire to reduce wire-downs and improve safety, and to evaluate the poles and pole-top equipment for replacement to balance the crossarms and improve reliability. As such, deconductoring fits into the scope of the 4.8kV Hardening Program.

Q38. How can customers stay informed about 4.8kV Hardening work being performed in their area?

A38. Customers interested in seeing if 4.8kV Hardening work is being performed in their respective area can visit the Company's external website at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e. These maps are regularly updated to inform our customers of the reliability work the Company is performing on their behalf, to visually display work completed in the last 6 months, and to show work scheduled to be completed within the next 12 months. Please note that the 4.8kV Hardening and PTMM Programs are called "Upgrading Existing Infrastructure" in the map provided on this website. This map also shows Tree Trimming, Customer Excellence (called "Rapid Response"), and Circuit Conversion (called "Rebuilding Significant Portions of the Grid"). A current example of this map showing only the Upgrading Existing Infrastructure layer can be seen in Figure 6.

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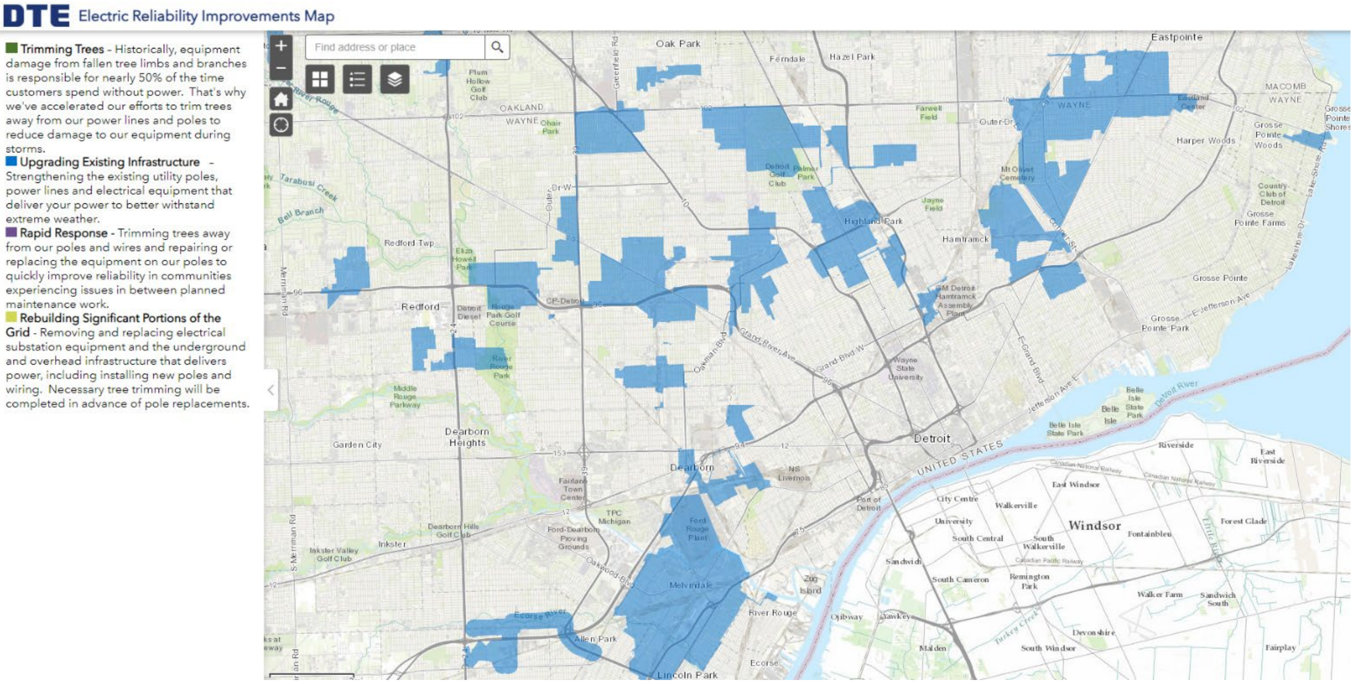
Figure 6. Upgrading Existing Infrastructure Map



The Pole and Pole-Top Maintenance and Modernization Program (PTMM)

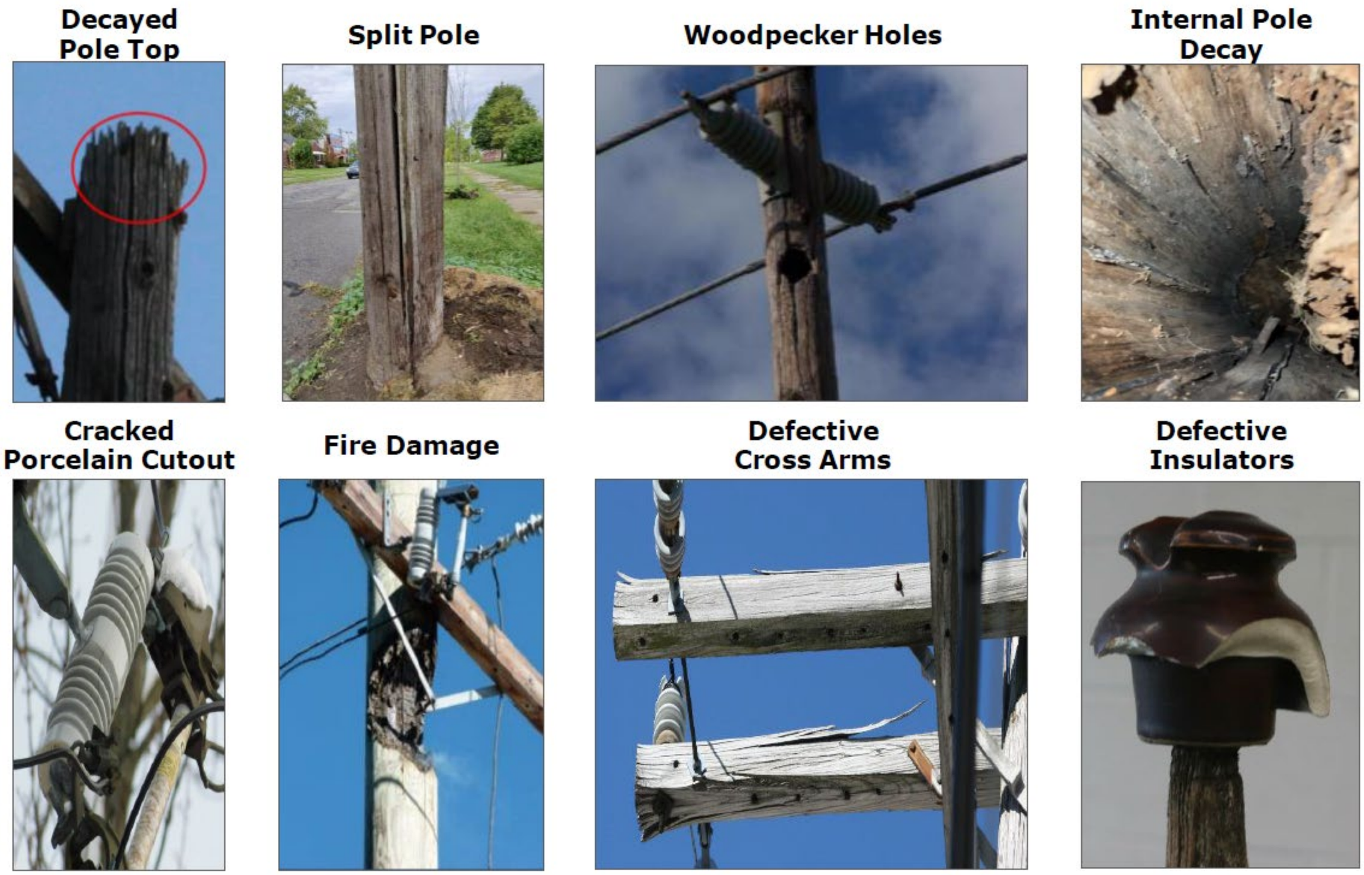
Q39. What is the Pole and Pole-Top Maintenance and Modernization (PTMM) Program?

A39. The PTMM Program is the Company's program to inspect and maintain overhead distribution equipment, in support of improving the system reliability and resilience to weather, storms, and tree-related events as described below. Formerly called the Pole-Top Maintenance (PTM) Program, the modernization aspect was included in late 2019, and the program renamed to PTMM to reflect updated standards for inspection methods, and updated standards for equipment, and materials.

Q40. What are the drivers of the Company's PTMM Program?

A40. Approximately 70% of DTEE's infrastructure is overhead. Overhead equipment failures cause approximately 25% of all outages customers experience during all weather conditions, and over 30% of all outages customers experience excluding Major Event Days (MEDs). Poles and pole-top equipment are some of the most critical and visible parts of the distribution and subtransmission grid, and are continually exposed to harsh conditions (e.g., tree strikes, ice, heat, rain, lightning, sunlight, and wind), causing them to degrade, weaken, and fail over time. Examples of equipment damage, also called inspection defects, are shown in Figure 7.

Figure 7. Pole and Pole-Top Defect Examples



The Company has approximately 31,000 miles of overhead distribution and subtransmission lines, collectively containing approximately one million Company-owned wood poles and associated pole-top equipment. Utility poles have a useful life expectancy of approximately 40-50 years and have elevated failure risk as they age beyond their useful life. Useful life is a standard industry term that does not represent the actual life of an asset, but rather the age at which an installed asset is expected to experience increasing failure rates and deliver reduced performance, such that it is often more prudent to replace than to continue to repair and maintain. Figure 8 displays DTEE owned utility pole counts currently in use in the system by age range.

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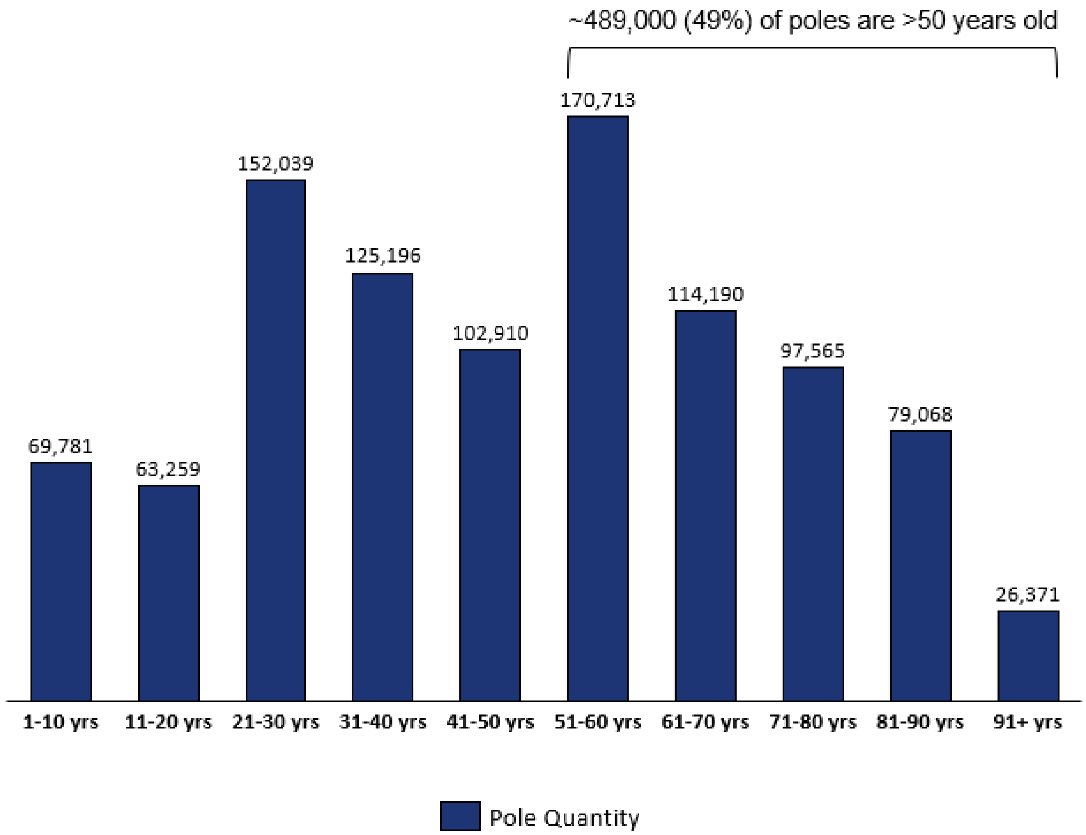
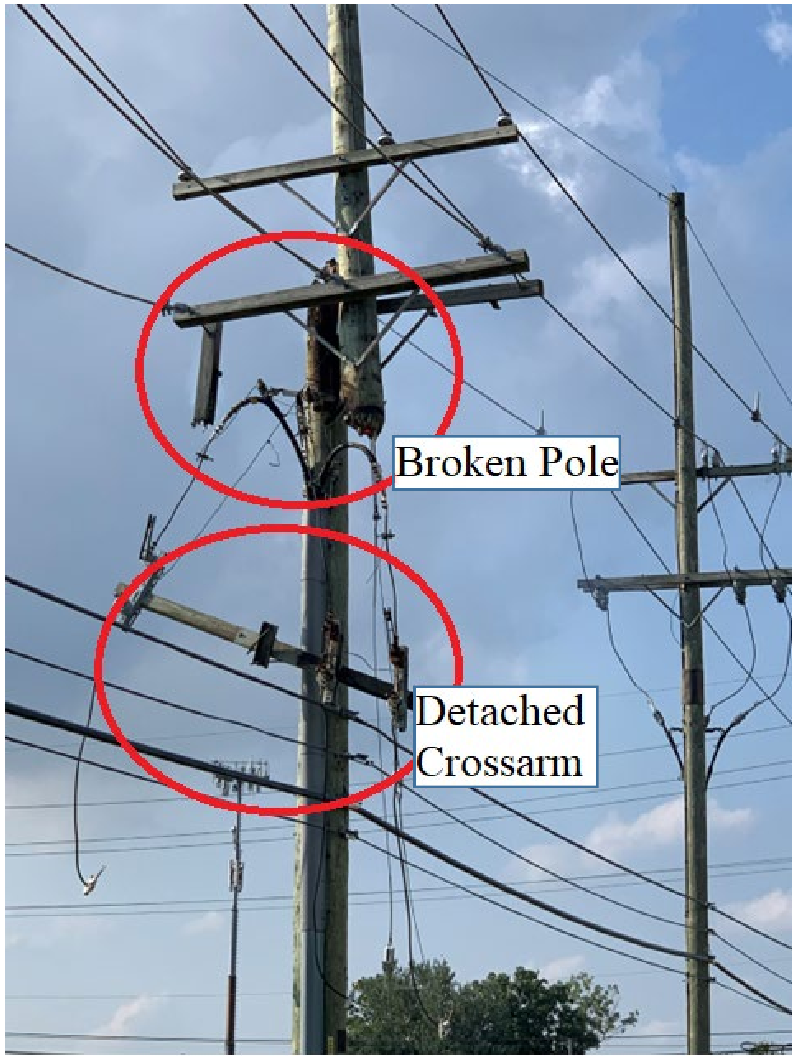
Figure 8. DTEE Poles by Age



Aging poles and pole-top equipment increase the risk of overhead equipment failures, which can subsequently cause outages. In addition to outages, examples of incidents that can occur in the event of pole and pole-top equipment failures include property damage, fires, and traffic accidents. Additionally, long and costly customer outages can result when this equipment fails unexpectedly from tree impacts or from other causes. Figure 9 displays an example of a pole-top equipment failure.

Figure 9. Overhead Pole-top Failure – Example



Pole and pole-top maintenance programs are standard utility industry programs that inspect circuits for damaged or defective poles and pole-top equipment, replacing them before they cause failures. Details regarding industry benchmarking the Company has conducted can be found below.

Q41. What benchmarking has the Company performed on PTMM?

A41. The Company has performed three benchmarking studies in 2018, 2021, and 2022 on the PTMM practices at fifteen peer utilities. While these studies varied in what portion of the PTMM programs were in focus, the Company found that all of the utilities had some sort of maintenance program to proactively address defective pole and pole-top assets in the field before they fail. Additionally, the benchmarking identified that the Company's inspection standards, including a 10-12 year pole inspection cycle, are in line with other utilities. Table 6 displays the Pole Inspection and Pole-Top Inspection cycle identified in seven of the utilities located in the Northeast and Midwest, indicating that most utilities operate on a 10-year (or less) cycle time for pole inspections and construction, and a 5-year cycle time for pole-top inspections and construction.

Table 6. PTMM Benchmarking

	Company 1 Northeast	Company 2 Northeast	Company 3 Midwest	Company 4 Midwest	Company 5 Midwest	Company 6 Midwest	Company 7 Midwest
Pole Inspection Cycle	10 years	5 years	10 years	10 years	10 years	12 years	8-12 years
Pole-Top Inspection Cycle	4 years	5 years	5 years	5 years	5 years	12 years	8-12 years

In addition to industry utility benchmarking, the Company consulted multiple industry expert publications and guidelines when developing and updating its PTMM program policies, as noted in Table 7.

Table 7. Industry Standards & Guidelines

Summary of Industry Standards and their Application in DTE's Pole Inspection Specification

Report	DTE Application
IEEE National Electric Safety Code (NESC)	• Per the NESC standard, 67% pole strength is used as the threshold to accept or reject a pole in DTE's specification
Rural Utilities Services UEP Bulletin 1730B-121	• The report outlines the frequency of pole inspection cycle of 10 years in Michigan • DTE's specification leveraged the guidelines in this report for other conditions aside from pole strength that could justify rejection of a pole such as severe woodpecker hole damage and split top • DTE also leveraged this report for classifying a rejected pole as a restorable reject where a remedial treatment is applied or a non-restorable reject where the pole is replaced
Wood Pole Maintenance Manual (2012) Oregon State Forest Research Lab	• The Oregon State Forest Research Lab report references the NESC safety standard for pole strength and UEP Bulletin pole classifications as described above, further validating the practice as industry standard • The report provides a sample pole inspection procedure that details various methods and equipment to inspect poles – Methods include excavation, partial excavation, sounding, boring, shell thickness measurements for evidence of decay, and applying remedial treatment to reinforce poles – DTE's pole inspection specification leverages the methods outlined in the report
American Wood Protection Association (AWPA) M13-07 Guidelines for a Pole Maintenance Program	• The AWPA report details methods for inspection, similarly to the Oregon State Forest Research lab report, further validating the practices as industry standard • The report includes additional consideration in the design of a pole inspection program, such as workforce/personnel and data management

Q42. How has this benchmarking and industry research impacted the way the Company manages its PTMM program?

A42. The Company has continued to use internal expertise, combined with benchmarking and industry standards, to develop and update the PTMM program and associated specifications to ensure best practices are implemented timely to improve reliability for customers. Based on these findings, the Company is aspiring to implement a PTMM program capable of inspecting, and completing the required construction, for poles on a 10-year cycle and pole-top equipment locations on a 5-year cycle to match the industry best practice identified in the benchmarking efforts discussed above.

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Q43. What is the scope of DTEE's PTMM Program?

A43. The PTMM Program inspects all wood poles and all pole-top equipment on distribution and subtransmission overhead circuits, and identifies and replaces poles and pole-top equipment that fails inspection. The PTMM Program scope includes all overhead circuits except those included in the 4.8kV Hardening Program.

The PTMM Program's work activities are described below:

1. Poles are inspected for damage that will undermine structural integrity.
    - (a) Poles younger than 20 years are visually inspected above grade.
    - (b) Poles older than 20 years are visually inspected and excavated below grade level and physically tested.
2. Poles which fail inspection are treated and reinforced, or replaced.
3. Trees are trimmed, as required, to support construction activities.
4. Pole-tops and pole-top equipment are visually inspected for damaged and/or defective equipment.
5. Pole-top equipment which fails inspection is replaced. Examples include:
    - (a) Damaged wooden crossarms are replaced with fiberglass crossarms.
    - (b) Damaged/defective porcelain cutouts are replaced with polymer cutouts.
    - (c) Damaged/defective porcelain insulators are replaced with polymer insulators.

Figures 10 and 11 show the improvements made before and after PTMM is complete at a pole-top location.

Figure 10. Before PTMM – Example

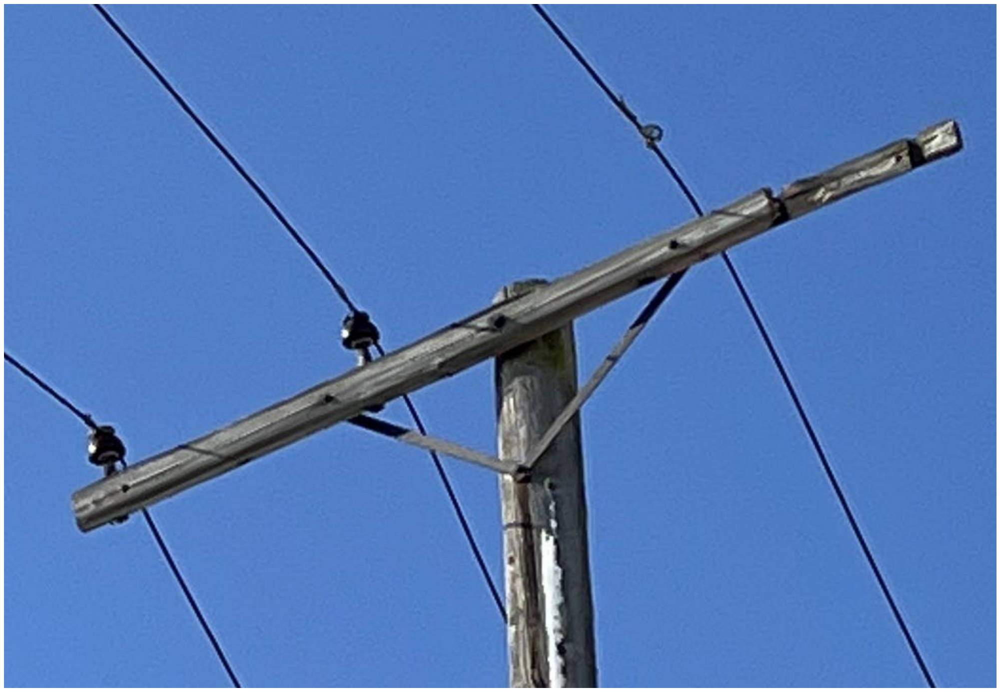

Figure 11. After PTMM – Example

Q44. Does the PTMM Program replace poles and pole-top equipment based solely on age?

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A44. No. The PTMM Program inspects poles and pole-top equipment and only replaces those which fail inspection.

Q45. How does the Company decide whether a pole should be reinforced or replaced?

A45. The Company's pole inspection process is shared in Exhibit A-23, Schedule M9 Pole Specification. This exhibit contains the inspection process, pole data collected and calculated, and the decision criteria for determining whether a pole should be treated, reinforced, or must be replaced.

The following data is collected on poles older than twenty years: measured circumference at groundline, measured shell thickness at groundline, minimum measured pole circumference below groundline, measured external pole decay, measured internal pole decay, and orientation of the pocket in regard to line of lead. These data points are used to calculate 1) groundline effective circumference, 2) percent remaining pole strength, and 3) groundline condition of the pole. Figure 12 shows pole testing and inspection processes.

As a result of these inspections and calculations, poles are classified as acceptable, restorable rejects, or non-restorable rejects. Acceptable poles may be treated internally and/or externally depending on the specific circumstances. Restorable reject poles may be treated and/or reinforced but must be replaced instead if they meet the criteria listed below that disqualify them from reinforcement. Non-restorable reject poles are replaced.

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All poles below 100% strength are candidates for internal treatments unless they must be replaced. Internal treatments are designed to protect the heartwood of the pole against fungus and insect attacks but are not used on poles that do not have measurable evidence of decay, voids, infestations, are near water, at sites with well water, on schoolgrounds, farmland, or vegetable gardens.

All acceptable and restorable reject poles (except those that must be replaced due to the criteria listed below that disqualify from reinforcement) that were fully excavated are treated with exterior groundline treatment. External groundline treatments are designed to protect the outer shell of the pole at groundline and reduce the loss of residual circumference due to decay. Poles that are 65 feet or shorter and are measured to determine if they have 67-99% of their strength remaining and are therefore deemed acceptable and are candidates for external groundline treatments. Poles that are 70 feet or taller and are measured to determine if they have 75-99% of their strength remaining and are therefore deemed acceptable and are candidates for external groundline treatments.

The Company's pole inspection standard is in line with the Institute of Electrical and Electronics Engineers (IEEE) National Electrical Safety Code standard that poles 65 feet or shorter fail inspection if they are below 67% of their original strength, and must be treated, reinforced, or replaced. Poles that are 70 feet or taller fail inspection if they are below 75% of their original strength, and must be treated, reinforced, or replaced.

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Poles that are 65 feet or shorter and are measured to have 15-66% of their strength remaining, are deemed restorable rejects. Poles that are 70 feet or taller and are measured to have 15-74% of their strength remaining, are deemed restorable rejects.

All poles of any height that are measured to have less than 15% of their strength remaining are deemed non-restorable rejects.

The following criteria make a pole ineligible for reinforcement per the Company's standards:

- An excessively leaning pole (e.g. a 40-foot pole leaning 7 inches or greater at a height of 5 feet above grade) cannot be reinforced unless it is it possible to straighten;
- A pole damaged by carpenter ants;
- Poles supporting wire crossing railroad tracks or highways
- Poles that were treated in the past with "Cellon" processes
- Poles cannot be reinforced under the following conditions:
  - Poles in non-testable locations and > 50 years old
  - Poles with less than 15% of their original strength
  - Poles identifiable as restorable candidates but not pass above grade inspection
  - Poles with an average sound shell thickness of less than 1"
- Non-DTEE-owned poles;
- Poles smaller than class 5 (e.g. 6, 7 ,8, 9);
- DTEE Riser poles;
- Poles within 100' of school property or water locations;

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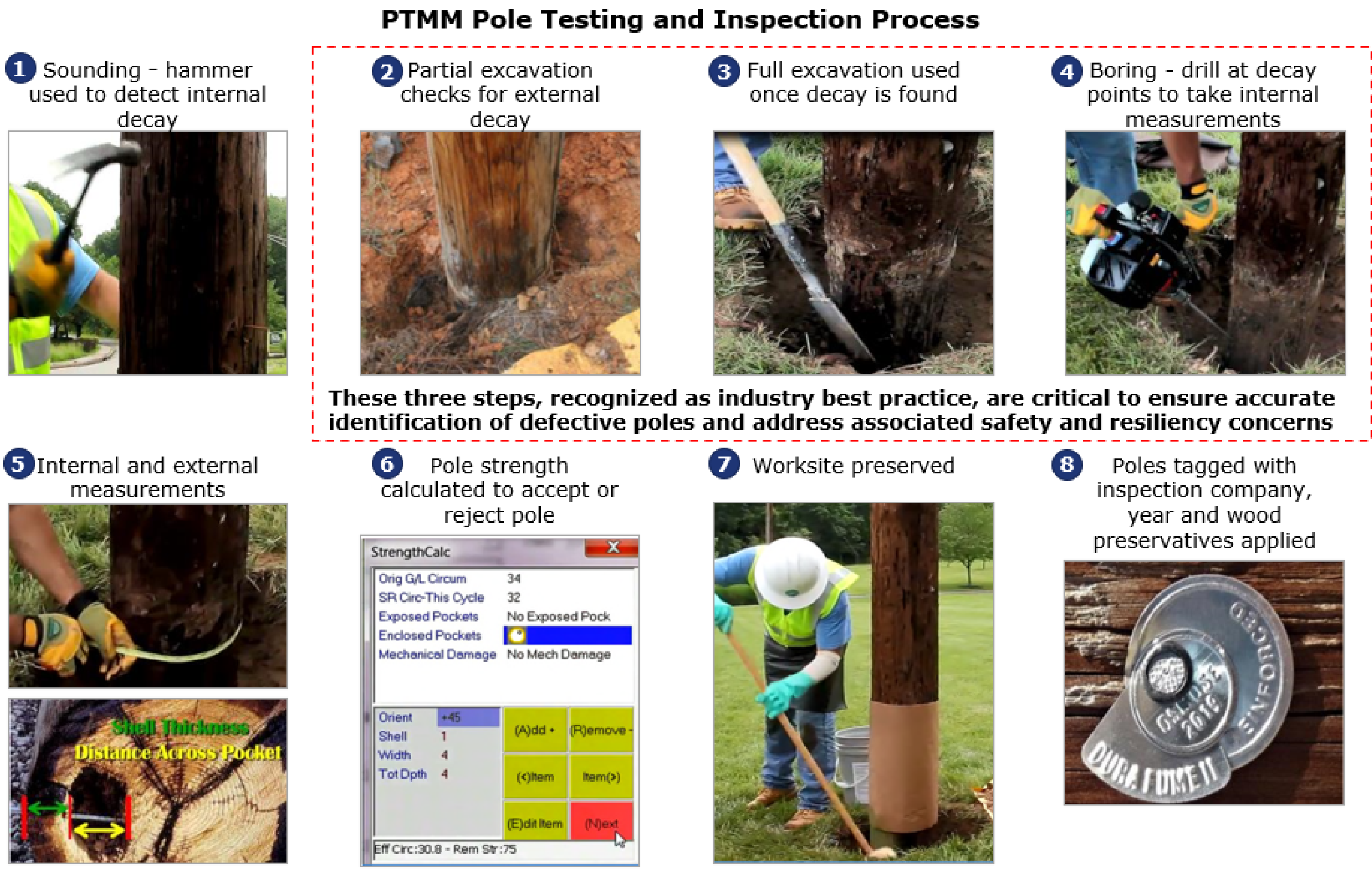
- Poles that are not candidates for remedial treatments;
- Electrical cable poles; and
- DTEE owned poles with no electrical overhead conductor

Additionally, poles that fail visual inspection due to the following cannot be reinforced:

- Shell rot or surface rot decay outside ground line area
- Woodpecker holes around or below the hardware that appear hollow
- Split tops that affect the integrity of bolts or equipment
- Split tops that do not have a bolt running perpendicular to the split
- Decayed tops with decay and crowning close to hardware
- Spur cut that results in 1" of the pole outer shell being removed
- Compression wood damage resulting in horizontal cracking that penetrates 1" deep into the shell and covers a large surface

Poles that fail inspection and are not eligible for reinforcement based on the criteria listed above are replaced.

Figure 12. Physical Pole Testing and Inspection



Q46. How does the Company decide whether pole-top equipment should be replaced?

A46. The Company's pole-top inspection process is shared in Exhibit A-23, Schedule M10 Pole-Top Specification.

In general, the following items are examples of what is replaced if they are found to be environmentally hazardous, broken, cracked, decayed, melted, burned, arcing, or missing:

- Transformers
- Cutouts

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- Crossarms
- Braces
- Brackets
- Insulators
- Arrestors
- Hot taps
- Ground wire
- Ground wire molding
- Conductors
- Spools
- Hardware (nuts, bolts, etc.)

Q47. Did the Commission address the PTMM Program in Case No. U-21297?

A47. The Commission approved cost recovery for PTMM in Case No. U-21297 at an investment level of $63.45 million annually, however they expressed concerns regarding the clarity around recent increases in investment levels.

Q48. Has the MPSC provided guidance on an appropriate cycle for pole inspections in the past?

A48. Yes. On November 20, 2009, the Michigan Public Service Commission Staff published the "Utility Pole Inspection Program Investigation Staff Report". In that report, the Staff recommended that DTEE achieve a 10-12 year pole inspection cycle frequency to correlate with the standard recommended by the USDA Rural Utility Service for Michigan's decay zone. The Staff also requested DTEE to provide a brief Pole Inspection Report to Staff each year by September 1, beginning in 2010.

Q49. Has the Company provided annual pole inspection reports to the MPSC Staff?

A49. Yes, the Company has provided pole inspection reports to Staff annually since 2010.

Q50. What did the Commission order regarding PTMM inspection reporting and benefit cost analysis in Case No. U-21297?

A50. The Commission ordered the Company to prepare an annual pole and pole-top inspection report, that is similar to the Company's Annual Tree Trimming Report, and to complete a benefit cost analysis of the program.

Q51. Is the Company preparing an annual PTMM report to comply with the Commission's directive described above?

A51. Yes, at the time this testimony was being prepared, the data for the required report was being assembled.

Q52. Has the Company performed a benefit cost analysis (BCA) for PTMM to comply with the Commission's directive as described above?

A52. Yes. The Company completed a BCA, as directed, in February 2024. The Company collaborated with an external consulting firm to create a BCA for PTMM based on a methodology utilized by other utilities in other states (such as IN, OH, IL, MD, FL, and OK). This BCA utilized a bottoms-up, asset-based approach to capture the present value of the benefits over a 40-year study period, compared to the upfront investments to implement the PTMM program, creating a benefit cost ratio by circuit. For this statistical model, the benefits are calculated as the avoided cost of emergent reactive events caused by running equipment to failure, and includes the use of the LBNL ICE calculator to model customer impacts from these outages. The "upfront investments"

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are calculated by totaling the investment forecasted to properly complete pole and pole-top inspections, pole remediation and reinforcements, and pole and pole-top equipment replacements required per the inspection process. The overall average system benefit cost ratio for the system was calculated at 5.7, meaning if PTMM could be conducted on 100% of the Company's distribution grid, the benefits realized by the customers for completing PTMM would be 5.7 times greater than the benefits realized if the Company decided to run all poles and pole-top equipment to failure. The PTMM BCA Whitepaper is included to this instant case as Exhibit A-23, Schedule M13.

Q53. What changes has the Company made to its PTMM program in recent years?

A53. The Company's PTMM program has gone through a transformation over the past few years to support a more resilient overhead infrastructure, including alignment with the industry standards discovered through benchmarking activities. The first improvements the Company implemented followed the first set of benchmarking in 2018 and 2019, and included updating the pole inspection process (as defined above), and transitioning the previous Pole Top Maintenance (PTM) Program to the Pole and Pole-Top Maintenance and Modernization Program. The addition of "Modernization" simply meant that when a pole, or piece of pole-top equipment failed inspection, the Company would no longer replace like-for-like, rather the equipment would be replaced with the equipment that met the new, higher-level specification to incorporate more modernized equipment into the field.

The second set of improvements were implemented in 2021 and 2022, and included only using PTMM inspections solely (and no longer utilizing Joint Use inspections) to meet the 10-12 year cycle, and assembling a new team to enhance the PTMM program

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management including more rigorous quality reviews of work completed and implementing process improvements based on industry standards learned through benchmarking. The decision to no longer utilize Joint Use inspections in the PTMM program was due to the fact that they were less rigorous than PTMM inspections and focused on telecommunications equipment and clearances, rather than focused on the Company's pole-top equipment, and were no longer suitable to use for PTMM.

The third set of improvements were implemented in 2023, and could be grouped into two categories – 1) inspection quality control, and 2) process improvements. First, the inspection quality control improvements were implemented prior, during, and post inspections to ensure adherence to DTEE's PTMM specification. They include: hands-on training required for all inspectors including a knowledge test; inspectors are equipped with picture-based field manuals to help identify defective equipment; DTEE field leads provide daily guidance to inspectors and perform quality checks on work completed; and more than 50% of all job packages receive a field audit from a third-party to ensure accuracy. Second, the PTMM program team performed multiple process improvements including developing a Geographic Information System (GIS) based application (app) used to digitize inspection results, and streamline the remediation of defective assets. Now, when the inspector submits their inspection findings into the app, the team processes a completed construction job package that includes a material list, compatible units (which define the specific work to be completed), and four pictures of each work location. This allows the PTMM program management team real-time visibility into field activities, improved coordination of resources, and reduces the cycle time from inspection to construction completion.

Q54. What has led to the increase in PTMM investments in recent years?

A54. Historically, the PTMM program has measured number of poles inspected, number of poles replaced, number of poles reinforced, and total line miles modernized (meaning pole-top equipment locations where construction is complete to remediate failed equipment identified through the inspection process). The largest cost driver of the PTMM Program is the increased quantity of defective pole and pole-top locations identified through the inspection process.

As seen in Table 8 and Table 9 below, the stringent adherence to PTMM standards and enhanced quality controls has led to an increased volume of defects identified and remediated on our system. In 2022 and 2023, the program increased defective pole replacements by over 2,900 poles per year driven by 1) higher pole reject rates, 2) higher levels of PTMM inspections (not including Joint Use), 3) and a focus on backlog reduction. During the same timeframe, the program increased defective pole-top equipment replacements by approximately 5,500 pole top locations per year driven by 1) higher pole-top defect rates based on updated inspection standards, 2) enhanced quality control (training, field audits, etc.), 3) higher circuit miles being addressed. In this instant case, the planned investment increases per circuit mile in the PTMM Program are based off the higher pole and pole-top equipment location failure rates that have been recorded since improvements were made to the program.

Table 8. PTMM – Pole Defects per Mile

	2019	2020	2021	2019-2021 Average	2022	2023
Poles Replaced per Circuit Mile	1.3	1.0	0.7	1.0	2.9	3.7

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Table 9. PTMM – Pole-Top Defects per Mile

	2019	2020	2021	2018-2021 Average	2022	2023
Pole-Top Locations per Circuit Mile	1.2	1.2	2.1	**1.5**	3.6	12.7

Q55. What work did the PTMM program complete in 2023?

A55. The PTMM program completed construction on 1,418 circuit miles which included approximately 9,500 pole-top equipment locations, and replaced 3,814 poles. Additionally, the program completed inspections on 12,650 poles.

Table 10. Historical PTMM Work Units Performed

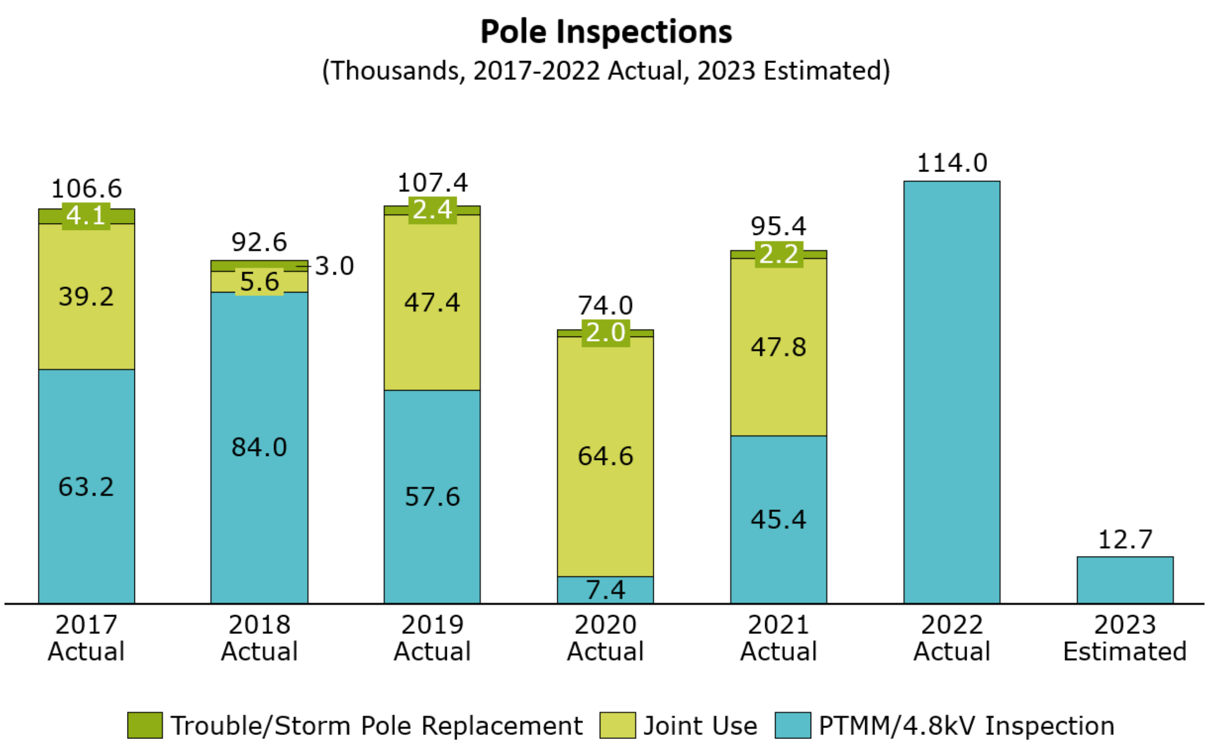
	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast
Circuit Miles	1,027	1,496	1,541	1,562	1,418
Poles Replaced	1,333	1,431	1,016	4,537	3,814
Poles Reinforced	2,717	27	109	1,116	150
Pole Top Locations Replaced	1,232	1,795	3,236	5,621	9,500
Capital Investment ($ thousands)	$26,892	$36,364	$31,647	$80,879	$79,075

Q56. Why did the PTMM program complete fewer inspections in 2023 than in prior years?

A56. Prior to 2023, the Company had been consistently meeting the expectation of inspecting poles on a 10-12 year cycle following the MPSC direction discussed above (Figure 13).

However, the Company was unable to complete the required construction activities to remediate the failing poles and pole-top equipment locations identified in a timely manner with its total investment, thus a backlog of construction work was created. Additionally, as the Company stopped utilizing Joint Use inspections in 2022, and only used PTMM Program inspections, there was an increase in the number of poles and pole-top equipment locations that failed inspection per circuit mile. This compounded the issue and grew the backlog of work which failed inspection and required construction. At the beginning of 2023, the Company had a total of 4,695 poles and 14,654 pole-top equipment locations that failed inspection, and made the strategic decision to pause most new inspections, and focus efforts on completing the required construction already identified.

Figure 13. Pole Inspections 2017-2023



Q57. What is the status of the PTMM work ready for construction?

A57. As of January 1, 2024 the Company had 3,744 poles and 9,353 pole-top locations that failed inspection and still require construction to be completed.

Q58. Is the Company planning to complete inspections in 2024 and 2025 consistent with the 10-12 year inspection cycle previously completed?

A58. Not in this instant case. Since the customer only benefits from the PTMM program once the construction is complete, and the Company does not want to create a situation where the backlog of work begins to rise above approved investment levels, DTEE has made the strategic decision to only conduct pole and pole-top equipment location inspections on the amount the PTMM program is funded to complete the associated construction activities. Given the current approved funding levels for PTMM, and the pole and pole-top equipment location failure rates, the Company will not be able to meet the 10-12 year pole inspection cycle in this instant case. However, the Company is planning to continue to seek approval to increase PTMM investment levels in this instant case and beyond, to allow a return to a 10-year pole inspection and construction cycle, and the 5-year pole-top equipment location inspection and construction cycle to match the industry standard programs identified in benchmarking activities. The specific inspection plans for 2024 and 2025 are discussed further below.

Q59. How has the PTMM Program changed the way it prioritizes circuits for 2024?

A59. Due to the increase in capital investment required per circuit mile discussed above, and the supported annual funding for PTMM at $63.45 million, the Company has created a method of prioritizing work based on the worst reliability circuits for 2024.

This analysis includes categorizing circuits into four tiers, based on the frequency and magnitude of reliability issues customers experience (Table 11), where Tier 1 are the worst performing circuits and Tier 4 are the best performing circuits.

Table 11. Circuit Reliablity Tiers

Circuit Tier	Prioritization Criteria	Circuit Count	Customer Count (thousands)
Tier 1	AW SAIFI or AW SAIDI in worst 500 circuits for 3+ years (2019-2023)	365	426
Tier 2	AW SAIFI or AW SAIDI in the worst 800 circuits for 3+ years (2019-2023)	322	389
Tier 3	All Circuits not classified as Tier 1, 2, or 4	461	491
Tier 4	AW SAIFI or AW SAIDI in the best 1,000 circuits for 3+ years (2019-2023)	1,118	880
Total		**2,266**	**2,186**

Circuits that are ranked in the worst 500 performing circuits (based on All Weather (AW) SAIFI and AW SAIDI) from three prior years are categorized as Tier 1, and the highest reliability risk. Circuits that are ranked in the worst 800 performing circuits from three prior years, are categorized as Tier 2, and the second highest reliability risk. Circuits that are ranked in the best 1,000 performing circuits from three prior years are categorized as Tier 4, and all remaining circuits are categorized as Tier 3.

This method of determining reliability tiers was validated using January through July 2023 reliability data as seen in Figure 14, where the results of the analysis show that

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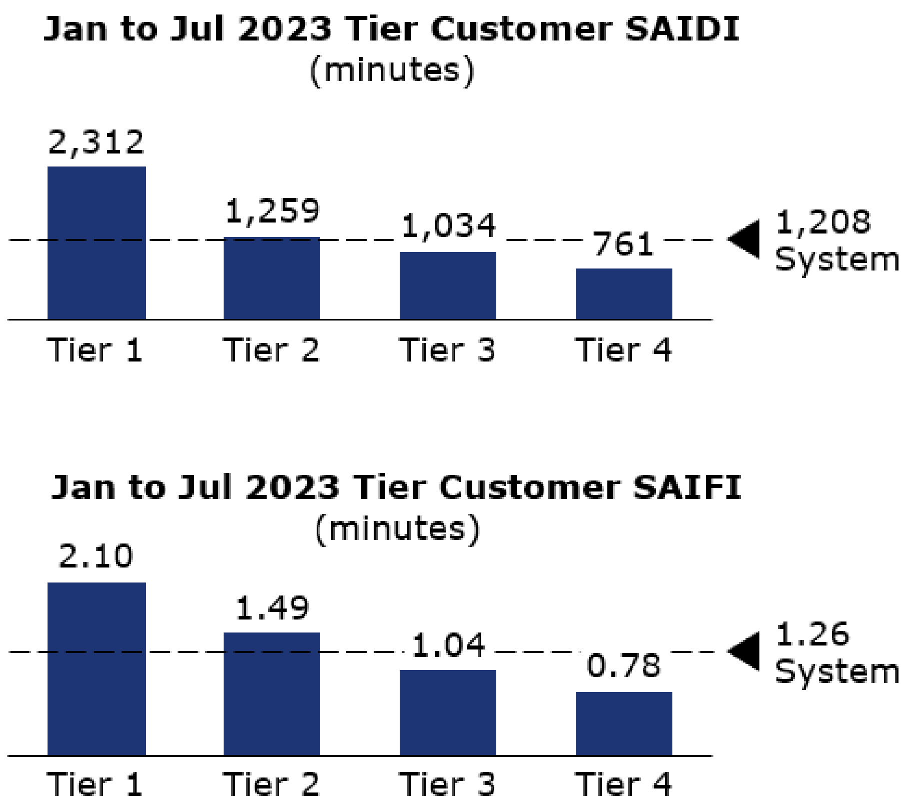
circuits ranked as Tier 1 and Tier 2 have worse AW SAIFI and AW SAIDI performance than Tiers 3 and 4 and the system-wide average.

Figure 14. Distribution Circuit Reliability Tier Comparison



Once the tiers were identified, the Company created the 2024 construction plan, optimizing the selection of Tier 1 and Tier 2 circuits, the work that was already in process of construction, and distributing the workload throughout the service territory. When the BCA discussed above was completed, the Company validated the 2024 workplan had a high benefit cost ratio.

Q60. How is the PTMM Program prioritizing circuits for 2025?

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A60. The Company selected circuits for 2025 based on the benefit cost ratios calculated by the PTMM BCA model and then further prioritized based on reliability risk tier to ensure they are reasonable and prudent for inclusion in the workplan.

Q61. Is the Company still working towards a 10-year pole and 5-year pole-top equipment location inspection and construction cycle in the PTMM program?

A61. Yes. However, while the Company is unable to execute a 10-year pole and 5-year pole-top cycle in the short term based on current inspection failure rates being realized through the PTMM inspection process, the Company plans to increase PTMM investments to reach a 10-year pole and 5-year pole-top cycle. As described above, the Company used the reliability tier model, and other operational data, to create the 2024 workplan based on the current approved investment level, and utilized the BCA output to validate the reliability benefit for the customers included on the selected circuits. In this instant case, the Company is requesting approval to increase investment in PTMM in 2025 to $121 million, still utilizing the reliability tier model and BCA output, to select the optimal mix of circuits to improve customer reliability. The Company has plans to continue to seek increases in investment levels in the PTMM program, consistent with PTMM inspection failure rates, beyond this instant case, to ultimately reach a 10-year pole, and 5-year pole-top equipment location inspection and construction cycle matching industry standard levels identified through benchmarking efforts discussed above.

Q62. What is in the Company's 2024 and 2025 PTMM workplan?

A62. Based on a planned investment level of $63.4 million consistent with the order in Case No. U-21297, the 2024 PTMM workplan includes replacing poles and pole-top equipment on approximately 750 circuit miles. This translates to replacing approximately 1,700 poles, and replacing pole-top equipment which has failed inspection at approximately 8,655 pole-top equipment locations. In addition, the PTMM program will inspect approximately 39,250 poles to support the workplan for future investment plans.

In this instant case, the Company is requesting approval to invest $121 million in the PTMM program to fund the 2025 workplan to replace poles and pole-top equipment on approximately 1,100 circuit miles. This translates to replacing approximately 3,965 poles, and replacing pole-top equipment that has failed inspection at approximately 13,800 locations. In addition, the PTMM program will inspect approximately 53,500 poles to support the workplan for future investments. The activity after the projected test year is covered in the IRM section of this testimony.

Table 12. PTMM 2024-2025 Workplan

	2024	2025
Circuit Miles	750	1,100
Poles Replaced	1,700	3,965
Poles Reinforced	100	200
Pole-Top Locations Replaced	8,655	13,800
Capital Investment ($ thousands)	$63,450	$121,000

Q63. What are the BCA analysis results of the 2024 and 2025 PTMM workplan?

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A63. When evaluating the subset of circuits included in the 2024 workplan, the benefit cost ratio calculated was 8.3. And the benefit cost ratio calculated for the subset of circuits selected for the 2025 workplan was 11. In both cases, the workplans include circuits that have a higher benefit cost ratio for completing PTMM than the system average, thus validating the Company's selection criteria of focusing on Tier 1 and Tier 2 circuits to maximize customer impacts while working towards implementing a full 10-year pole and 5-year pole top equipment PTMM cycle in future years.

Q64. How can customers stay informed about PTMM work being performed in their area?

A64. Customers interested in seeing if PTMM work is being performed in their respective area can visit the Company's website at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e. These maps are regularly updated to inform our customers of the reliability work the Company is performing on their behalf, to visually display work completed in the last 6 months, and work scheduled to be completed within the next 12 months. Please note that the PTMM and 4.8kV Hardening Programs are called "Upgrading Existing Infrastructure" in the map provided on this website. This map also shows Tree Trimming, Customer Excellence (called "Rapid Response") and Circuit Conversion (called "Rebuilding Significant Portions of the Grid"). A current example of this map showing only the "Upgrading Existing Infrastructure" layer can be seen in Figure 15.

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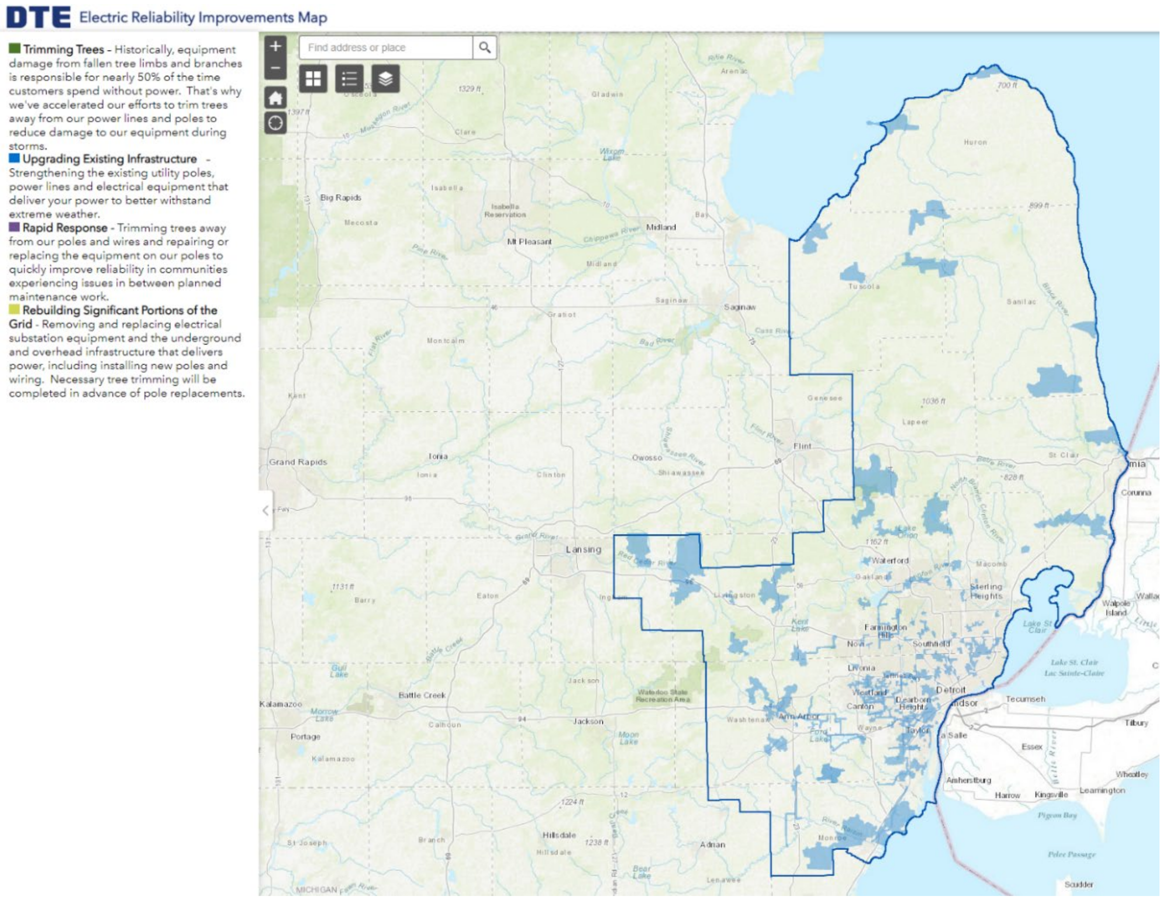
Figure 15. Upgraading Existing Infrastructure Map



__Substation Risk__

Q65. What are Substation Risk projects?

A65. Projects in this category are designed to remediate failures of substations that have already occurred, or to prevent catastrophic substation failures in the future. Because a substation typically supports several circuits, substation catastrophic failure events often impact a large number of customers. The events typically are caused by significant equipment failure such as a transformer or switchgear, fires, or flooding events. In addition to affecting a large amount of customers, they can result in lengthy outages because an entire substation is difficult to restore, with methods often limited to Mobile Fleet Program assets such as diesel generators and portable substations, or switching load to adjacent substations with available jumpering capacity. The amount of adjacent substation jumpering that can be achieved, and how quickly it can be implemented, is dependent on several factors such as same circuit voltage class, adequate existing capacity and cable/conductor size, and sufficient operating devices already installed in field. Substation Risk projects often target replacing at-risk switchgear within the substations in order to reduce the risk of major outages. Switchgear is an enclosure with breakers, relays, and wiring, and a breaker or cable failure inside a switchgear can take out multiple circuits at once.

These Substation Risk projects are prioritized utilizing the Global Prioritization Model (GPM) as discussed in more detail in Company Witness Kryscynski's testimony, at substations where deployment of Mobile Fleet Program assets cannot restore the entire substation load; in other words, customers will be out for more than 24 hours in the event of a failure. Details of the projects included in this instant case can be found below and in Exhibit A-23, Schedule M5.

Q66. Please describe the drivers of the Substation Risk: McGraw project.

A66. Record heavy rains in June 2021 led to significant, catastrophic flooding in the McGraw substation. The sub-grade part of the substation was engulfed in storm water, which caused the failure of position breakers, busses, transfer busses, and house service panels. As a result, the substation experienced a total loss of load carrying ability that caused 6,000 customer outages lasting between 16 hours to 5 days based on the ability to restore power.

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Figure 16. Flooding Near McGraw Substation

The Company's initial emergency response included a mix of jumpering load away from McGraw to adjacent substations, and use of the Mobile Fleet Program portable generation equipment. All customers were placed back on utility power within two weeks after the flooding event by means of station jumpering and breaker replacement,

Figure 17. McGraw Substation Flooding – Example 1

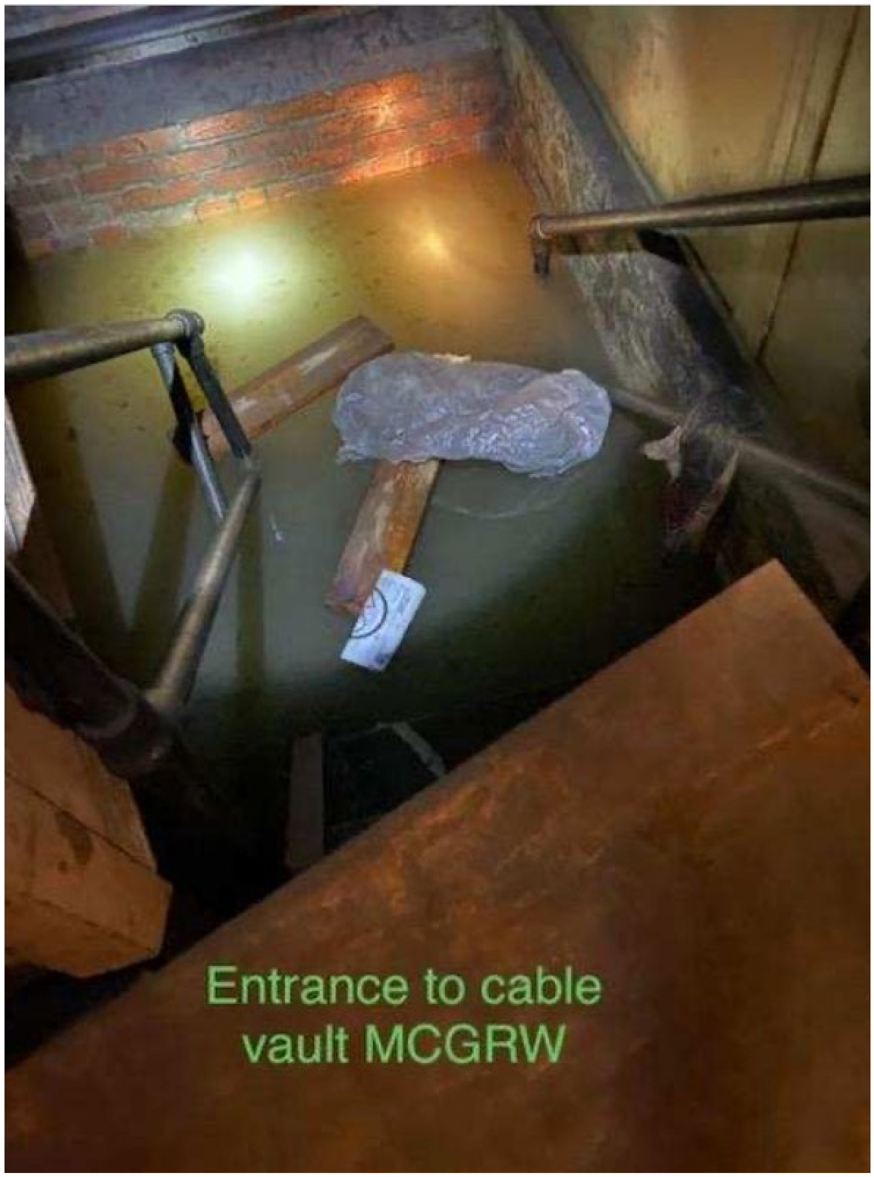
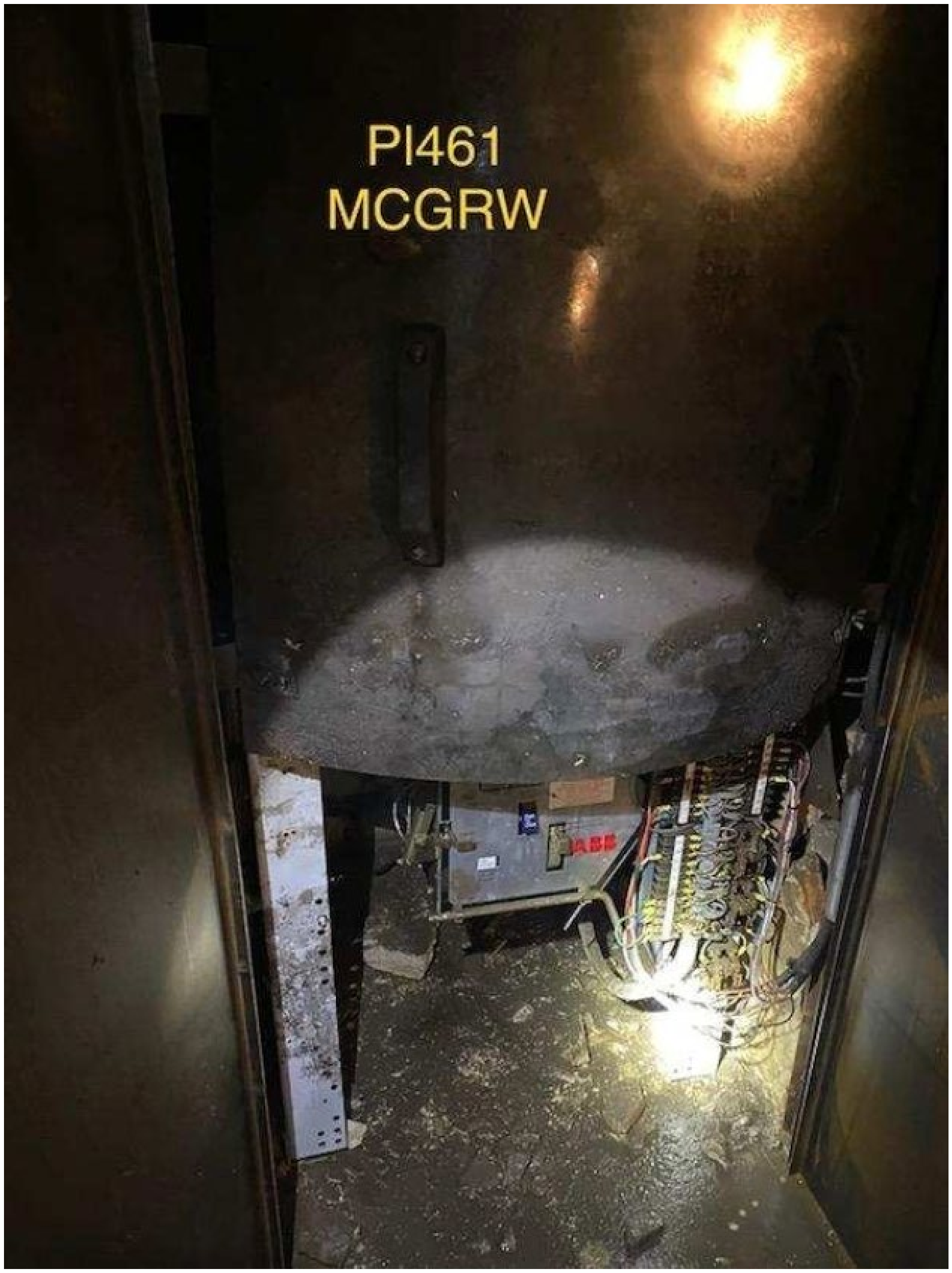


Figure 18. McGraw Substation Flooding – Example 2



however, the substation has continued using some Mobile Fleet Program equipment and a temporary overhead circuit (pole farm) constructed on City of Detroit and MDOT property to bypass damaged and inoperable substation equipment, until a permanent solution is constructed on DTEE property. While the current temporary configuration supports load day-to-day, it is higher risk than standard utility construction, and there have been subsequent outage impacts for these customers. For example, the portable substation in the field was struck by a vehicle and taken out of service, which caused additional outages to customers until a replacement could be installed. The temporary configuration also poses a safety risk due to the lack of automatic ground detection alarms to indicate a downed 4.8kV wire. Substation field personnel visit the substation daily to manually check for grounds at McGraw until the permanent facilities can be built. Additionally, customers have expressed concerns about the continued presence of the large temporary mobile equipment located in residential neighborhoods.

After the initial emergency response, the Company's engineers and field personnel assessed the substation's condition, as well as the long-term plans of the McGraw substation and surrounding circuits. The Substation Risk: McGraw project was created after these assessments with the goals of preventing future failures due to flooding and returning customers to normal utility service.

Q67. What is the scope of the Substation Risk: McGraw project?

A67. The scope of the Substation Risk: McGraw project is to:

i) Install new substation equipment on the second level including a new circuit feeder, transformer and ATO breakers, new relay and voltage control panels, and network/SCADA capabilities are being installed to increase reliability. Additionally, while all critical equipment has been moved out of the lower level, sump pumps and a manual diversion valve have been installed to improve response to any potential flooding in the basement.

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ii) Acquire land parcels and vacated right-of-way from the City of Detroit and MDOT to allow exterior expansion for equipment to be removed from the basement.

iii) Construct exterior expansion of substation equipment including two 24-4.8kV 10/12 MVA transformers with circuit switcher protection and a 9-position PDC, and network/SCADA capabilities installed to increase reliability.

iv) Decommission and remove failed substation equipment in the basement.

More details of this project can be found in Exhibit A-23, Schedule M5.

Q68. What are the customer benefits of the Substation Risk: McGraw project?

A68. This work will return customers fed from the McGraw substation to normal utility service, removing the necessity for the continued use of the mobile generation equipment, and the temporary pole farm, thus improving the reliability of service for all affected customers. This project will also greatly reduce or eliminate future flooding risk to the McGraw substation as all equipment necessary to serve customers will be located on the second floor of the substation or outside of the building (rather than the basement). The project is anticipated to be completed in 2024. Additionally, the permanent utility infrastructure will allow for the removal of the large temporary equipment that has been a customer concern.

Q69. Should the Commission approve investment in Substation Risk: McGraw project in this instant case?

A69. Yes. This project is necessary to serve the customers fed by the McGraw substation in a reasonable and prudent manner. This project will return McGraw back to full operability, remove all mobile generation equipment, eliminating the need for the temporary pole yard, build switching and redundancy for these circuits, and restore service to the customers with long-term utility equipment rather than the current temporary solution.

Figure 19. McGraw Substation – Temporary Pole Farm

Q70. Why was the Substation Risk: Flood Defense Program created?

A70. The Substation Risk: Flood Defense Program was created as a response to heavy rainfalls and flooding events that have been experienced in recent years at the Company's substations.

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Class C and D substations[9] were constructed in the 1930s and 1940s and were designed to contain critical distribution assets underground in their basements. These older substation designs rely on water-cooled equipment that requires a sewer connection, making them vulnerable to catastrophic failures due to abnormally heavy rains that can cause rapid flooding events.

The Company performed a detailed updated flooding risk analysis after the 2021 flooding events, and determined that five substations (Walker, Orchard, Madison, Frisbee, and Scotten) serving approximately 17,000 customers were at elevated risk and required flood mitigation measures.

Q71. What is the scope of the Substation Risk: Flood Defense Program?

A71. The scope of the Substation Risk: Flood Defense Program is to limit or prevent water intrusion in vulnerable substations by performing the following work at five Class C/D substations:

- Install one-way backflow prevention valves on existing sewer connected dewatering systems;
- Install emergency dewatering pumps to discharge at ground level during sewer backup events; and
- Seal conduit to help prevent water penetration into the substation.

[9] A Class C substation is a general-purpose substation with three or more radially-fed 24 to 4.8kV transformers, a 4.8kV transformer bus, a 4.8kV transfer bus, and a 4.8kV linkage bus, operated together to provide a parallel-operated service with a maximum degree of continuity. A class D substation is designed to include the installation of one or more 120 to 40/24kV transformers and several 40/24kV circuits. Class D substations are usually designed for two or more 120kV buses, 120 to 40/24 kV transformers, and 40/24kV buses. The design may also include 345 and 230kV buses and switching and associated transformation to 120kV.

This work will significantly reduce the risk of catastrophic failure at five substations to ensure that the 17,000 associated customers have a more reliable, resilient grid. The program is anticipated to be completed in 2024.

More details of this program can be found in Exhibit A-23, Schedule M5.

Q72. What are the customer benefits of the Substation Risk: Flood Defense Program?

A72. The Substation Risk: Flood Defense Program investments will reduce the risk of catastrophic failure of five at-risk substations, thus reducing the risk of extended outages for approximately 17,000 customers.

Q73. Should the Commission approve investment in Substation Risk: Flood Defense program in this instant case?

A73. Yes, in my opinion the MPSC should approve the Flood Defense program for cost recovery in the instant case because these investments are reasonable and prudent. As discussed in this section of my testimony, this project is necessary to respond to the substation flood analysis performed by installing back-flow prevention valves, emergency water pumps, and sealing conduit to reduce the risk of flooding causing catastrophic failure at the five identified substations which serve approximately 17,000 customers.

Q74. Why was the Substation Risk: Apache project created?

A74. A breaker position inside switchgear failed at the Apache Substation in 2015 which resulted in a significant area-wide outage affecting nearly 11,000 customers with 81% of affected customers being restored within 16 hours. The downtown business district of Troy, as well as surrounding commercial and residential areas were without electrical service for a prolonged period of time.

An assessment was performed after emergency repairs were made, which identified the remaining switchgear breakers were at-risk of a similar failure. A second catastrophic failure could result in the loss of all switchgear positions, and up to 16 MVA of stranded load. Stranded load occurs when customers cannot be restored by jumpering/transferring customers to an adjacent circuit or substation leading to prolonged customer outages across the entire substation area. In the example of Apache, while some load can be transferred to adjacent circuits, up to 16 MVA cannot be. The Substation Risk: Apache project was initiated to invest in appropriate replacements to prevent this potential second catastrophic failure.

Q75. What is the scope of the Substation Risk: Apache project?

A75. The scope of the Substation Risk: Apache project is to:

- Replace (1) at-risk 19-position switchgear with (2) new 12-position switchgear
- Replace (3) circuit switchers with S&C 2020 circuit switchers
- Build system cable termination on new switchgear for all 13 circuits
- Decommission the existing at-risk 19 position switchgear once load is cut over to new switchgear
- Install 12-5” conduit supporting substation exits
- Build (1) two-way manhole
- Build (9) three-way manholes
- Remove ~8,584 feet of old EPR and XLPE cable
- Install ~9,333 feet of new EPR cable

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- Replace (19) disconnect switches with pole-top switches at the station cable poles

Q76. What are the customer benefits of the Substation Risk: Apache Project?

A76. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages. The replacement of one at-risk 19-position switchgear with two new 12-position switchgear will also provide load relief to Apache circuits that exceed day-to-day limits. The project is anticipated to be completed in 2024.

Q77. Should the Commission approve investment in the Substation Risk: Apache project in this instant case?

A77. Yes. This project is necessary to reduce the risk of another catastrophic switchgear breaker failure at the Apache substation potentially resulting in an extended duration outage for the nearly 11,000 customers served by the Apache substation.

Q78. Why was the Substation Risk: Chestnut project created?

A78. The Chestnut substation has a single 19-position switchgear that is a single point of failure. A switchgear failure could result in the loss of all switchgear positions and a potential stranded load of 35 MVA with limited jumpering options, which would affect approximately 6,000 customers across three cities. This type of potential failure is similar to the Apache substation failure described earlier in my testimony, which would result in a long-duration outage for the affected customers. The switchgear itself was evaluated to be at high risk of failure based on a combination of years in service (53 years) and an equipment type that has experienced issues (GE air breaker). The

Chestnut project was initiated to mitigate the combination of high equipment risk and up to 15 MVA of stranded customer load by replacing the single at-risk 19-position switchgear with two new 12-position switchgear.

Q79. What is the scope of the Substation Risk: Chestnut project?

A79. The scope of the Substation Risk: Chestnut project is to:

- Replace (1) at-risk 19-position switchgear with (2) 12-position switchgear
- Replaced and relocate (3) capacitor banks
- Install ~500 feet of 15-5" concrete encased duct bank
- Install ~10,000 feet of EPR cable and associated branch and straight joints
- Install (17) OMNI-Rupters

More details of this project can be found in Exhibit A-23, Schedule M5.

Q80. What are the benefits of the Substation Risk: Chestnut project?

A80. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages, and will provide increased capacity to serve 18 distribution circuits, while the old configuration was only capable of serving 12 distribution circuits. The project is anticipated to be completed in 2025.

Q81. Was investment in the Substation Risk: Chestnut project requested in previous rate cases?

A81. Yes. The Substation Risk: Chestnut project was included in Exhibit A-12, Schedule B5.4 and Exhibit A-23, Schedule M4 exhibits for Case Nos. U-21297, U-20836, U-

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20561, and U-20162. Substation Risk projects were not included in my direct testimony in any prior rate cases before this instant case.

Q82. Should the Commission approve investment in the Substation Risk: Chestnut project in this instant case?

A82. Yes. Per the responses provided above, this project is necessary to reduce the risk of a catastrophic switchgear breaker failure at the Chestnut substation potentially resulting in an extended duration outage for the 6,000 customers served by the Chestnut substation.

Q83. Why was the Substation Risk: Savage Stranded Load project created?

A83. Following the fire at Apache substation, DTEE engineering teams assessed similar switchgear across its service territory for risk potential. Savage substation was identified as having a high-risk switchgear that did not have connections to adjacent substations that would allow for jumpering of the load in the event of a failure of the switchgear. This lack of jumpering capabilities created the risk of stranded load in the event of failure which was determined to be approximately 30MVA of load.

Q84. What is the scope of the Substation Risk: Savage Stranded Load project?

A84. The scope of the Substation Risk: Savage project was to:

- Extend conduit and cable to feed (7) new primary switch cabinets
- Establish tie points to adjacent circuits and substations

More details of this project can be found in Exhibit A-23, Schedule M5.

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Q85. What are the customer benefits of the Substation Risk: Savage Stranded Load project?

A85. Installing switch cabinets and establishing underground connections in the area accomplish the primary goal of mitigating stranded load but also provided future benefits. The new switch cabinets offer spare positions for future load growth as well as operating flexibility between Savage, Lochdale, and Apache circuits in the event of failures on these circuits. The project was completed in 2023.

Q86. Should the Commission approve investment in the Substation Risk: Savage Stranded Load project in this instant case?

A86. Yes. This project was necessary to reduce the risk of a catastrophic switchgear breaker failure at the Savage substation potentially resulting in an extended duration outage for the 3,000 customers served by the Savage substation.

Q87. Why was the Substation Risk: Belleville Switchgear Decommission project created?

A87. In the beginning of 2020, DTE's Engineering team identified the 4.8kV Belleville switchgear as at end of life. Breakers inside the switchgear required multiple repairs over the course of 5 years and there are no breakers replacements if they were to fail. Control wiring inside the cubicle also required re-wiring which involved extended planned shutdowns. The Belleville substation did experience a switchgear failure in 2022 which led to the condemnation of Bus 11 and limited operability. The Company's equipment engineers determined that the switchgear at Belleville substation is at-risk of further failures and needs to be fully decommissioned.

Q88. What is the scope of the Substation Risk: Belleville Switchgear Decommission project?

A88. The scope of the Substation Risk: Belleville Switchgear Decommission project is to:

- Bypass Belleville's 4.8kV switchgear by installing an overhead NOVA triple-single reclosers just outside of the substation
- Convert the 4.8kV portion of Belleville substation from a Class A to a Class T substation
- Reconfigure the (3) load-carrying circuits and throw-over circuit into (2) load-carrying circuits

This project is expected to be completed in 2024. More details of this project can be found in Exhibit A-23, Schedule M5.

Q89. What are the benefits of the Substation Risk: Belleville Switchgear Decommission project?

A89. Decommissioning and removing the partially failed, at-risk 4.8kV switchgear at Belleville substation and then reconfiguring the distribution circuits has enabled continued service for approximately 1,300 customers. This work has reduced the risk of extended outages for these customers if the switchgear were to experience another failure in the future.

A future 4.8kV Conversion project at Belleville substation is discussed in Witness Deol's testimony which will convert these circuits to 13.2kV and remove any remaining 4.8kV equipment at Belleville substation.

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Q90. Should the Commission approve investment in the Substation Risk: Belleville Switchgear project in this instant case?

A90. Yes. This project is necessary to reduce the risk of a catastrophic switchgear breaker failure at the Belleville substation potentially resulting in an extended duration outage for the 1,300 customers served by the 4.8kV Belleville substation.

Q91. Why was the Substation Risk: Voyager project created?

A91. Voyager is an industrial substation serving Stellantis. Stellantis has experienced several interruptions due to the at-risk high side motor disconnects at Voyager substation.

Q92. What is the scope of the Substation Risk: Voyager project?

A92. The scope of the Substation Risk: Voyager project was to:

- Install (4) piers for future circuit switcher installation
- Install anchor bolts for future circuit switcher installation
- Above grade work to replace the motor disconnects with new circuit switchers will be scheduled at a later time with the customer

More details of this project can be found in Exhibit A-23, Schedule M5.

Q93. What are the benefits of the Substation Risk: Voyager project?

A93. The below grade work was completed during a planned customer shutdown to avoid unnecessary customer outages. This below grade work will enable quicker replacement of the at-risk equipment during a future project to replace this equipment and improve reliability and operability at Voyager substation. This project was completed in 2023.

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Q94. Should the Commission approve investment in the Substation Risk: Voyager project in this instant case?

A94. Yes. This project was necessary to complete below grade work during a planned customer shutdown and this below grade work enables a future project to replace the at-risk equipment.

Q95. Why was the Substation Risk: Drexel project created?

A95. Position I at Drexel substation experienced a failure in July 2016 which resulted in a fire and damaged several positions in the Drexel switchgear. Approximately 7,500 customers are normally served by Drexel substation and over 3,000 customers were transferred to adjacent substations to restore service. Replacing the switchgear and restoring customers to their normal point of service will restore operability and reduce loading constraints in the area.

Q96. What is the scope of the Substation Risk: Drexel project?

A96. The scope of the Substation Risk: Drexel project is to:

- Install (1) 9-position switchgear
- Install (1) 15/20/25 MVA transformer to feed new switchgear
- Install 6,900 feet of EPR system cable from new switchgear lineup to existing cable poles
- Decommission and remove the damaged existing switchgear lineup
- Restore circuits to pre-fire configurations

More details of this project can be found in Exhibit A-23, Schedule M5.

Q97. What are the benefits of the Substation Risk: Drexel project?

A97. Completing the Drexel switchgear replacement project will restore the area to its normal configuration which reduces load on adjacent circuits and substations that have been temporarily serving Drexel customers since 2016. Decommissioning and removing the partially failed switchgear mitigates the risk of additional failures and extended outages for the area. This project will be completed in 2024.

Q98. Should the Commission approve investment in the Substation Risk: Drexel project in this instant case?

A98. Yes. Per the responses provided above, this project is necessary to mitigate the risk of additional failures and extended outages for customers in this area.

Q99. Why was the Substation Risk: Savage Switchgear Replacement project created?

A99. The Savage substation has a single 16-position switchgear that is a single point of failure. A switchgear failure could result in the loss of all switchgear positions and a potential stranded load of 30 MVA with limited jumpering options, which would affect approximately 3,000 customers throughout Troy. This type of failure would result in a long-duration outage for the affected customers. The switchgear has been determined to be at-risk of failure based on a review by the Company's equipment engineers. The combination of high equipment risk and high stranded customer load was why the Savage project was initiated. By splitting the existing single 16-position switchgear into two new separate 9-position switchgears, the equipment risk is reduced and the amount of stranded load (15 MVA) due to a single point failure.

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Q100. What is the scope of the Substation Risk: Savage Switchgear Replacement project?

A100. The scope of the Substation Risk: Savage Switchgear Replacement project is to:

- Remove existing parking area north of existing substation fence – approximately 7,800 sq. ft.
- Extend substation fence approximately 300 feet
- Perform site preparation and below grade for expanded substation yard
- Install concrete pads for new switchgear and three (3) 6 MVAR bus capacitor banks
- Install two (2) 9-position 2-high switchgear
- Install conduit and system cable to existing circuit cables feeding Savage circuits and neighboring circuits to enable jumper contingency
- Extend overhead 770 feet to establish two (2) portable ready locations
- Install two (2) sets of 3-333KVA regulators
- Decommission and remove existing 1960's vintage continuous line-up of one (1) 16-position switchgear at Savage substation

This project will be completed in 2024. More details of this project can be found in Exhibit A-23, Schedule M5.

Q101. What are the benefits of the Substation Risk: Savage Switchgear Replacement project?

A101. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages. It will also provide increased capacity to serve 12 distribution circuits while the old configuration was only capable of serving 10 distribution circuits. The project is anticipated to be completed in 2027.

Q102. Was investment in the Substation Risk: Savage Switchgear Replacement project requested in previous rate cases?

A102. No. The Substation Risk: Savage Switchgear Replacement project is new and was not included in any prior rate cases.

Q103. Should the Commission approve investment in the Substation Risk: Savage Switchgear Replacement project in this instant case?

A103. Yes. Per the responses provided above, this project is necessary to mitigate the risk of a switchgear failure at Savage substation which would result in a potential 30 MVA of stranded load affecting 3,000 customers throughout Troy.

Q104. Why was the Substation Risk: Seville project created?

A104. Position B at Seville experienced a failure in 2023 and after a review by the Company's engineers was determined unrepairable. Approximately 1,500 customers have been temporarily transferred to adjacent circuits to continue service. No spare positions currently exist at Seville substation to restore the area to normal configuration; therefore, switchgear replacement is necessary.

Q105. What is the scope of the Substation Risk: Seville project?

A105. The scope of the Substation Risk: Seville project is to:

- Replace one (1) failed 7-position switchgear with one (1) 9-position switchgear
- Install new transformer secondary cables

- Perform load transfers to re-establish Seville circuits to normal configuration

More details of this project can be found in Exhibit A-23, Schedule M5.

Q106. What are the benefits of the Substation Risk: Seville project?

A106. Restoring the area to normal configuration will allow the Company to return all circuits to normal operating condition and restore system redundancy in the event of future outage events. Additionally, the new standard 9-position switchgear will provide two spare circuit positions for future use to support customer growth as necessary.

Q107. Should the Commission approve investment in the Substation Risk: Seville project in this instant case?

A107. Yes. Per the responses provided above, this project is necessary to restore the Seville substation to a normal operating condition and return all circuits to loads that are within an acceptable range.

Q108. Why was the Substation Risk: Imlay project created?

A108. The Substation Risk: Imlay project is driven by safety concerns including:

- Substation equipment is within arm's reach when walking through the substation posing a safety hazard;
- Imlay substation has poor lighting conditions;
- Imlay substation has a transformer that operates vertically by lifting which poses a safety risk as it could result in a flashover during operation;
- Imlay substation is not built to DTEE standards;

- Imlay substation lacks necessary space to rebuild equipment on the existing 120x140ft site;
- Imlay substation is built on differing elevations which make retrofits or upgrades difficult;
- Imlay substation has a high 5-year average SAIDI of 549 minutes.

Q109. What is the scope of the Substation Risk: Imlay project?

A109. The scope of the Imlay Substation Risk project is:

- Replace OTSGO substation equipment to increase capacity and establish (2) new distribution circuits.
- Rebuild 30 miles of overhead conductor
- Convert 30 miles of 4.8kV to 13.2kV
- Transfer ~4.9MVA of load from IMLAY substation to OTSGO substation
- Decommission (1) 40-4.8kV substation (IMLAY).
- Pre-convert and convert about 30 miles (includes part of IMLAY and OTSGO).
- Transfer ~4.9MVA of load from Imlay Substation to OTSGO Sub

More details of this project can be found in Exhibit A-23, Schedule M5.

Q110. What are the benefits of the Substation Risk: Imlay project?

A110. This project will eliminate the substation electrical hazards at Imlay substation and improve the reliability for customers by rebuilding portions of the overhead circuits.

Q111. Should the Commission approve investment in the Substation Risk: Imlay project in this instant case?

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A111. Yes. Per the responses provided above, this project is necessary to mitigate the safety risks posed by its current configuration.

Frequent Outage Programs (CEMI)

Q112. What programs are included in Frequent Outage Programs?

A112. In addition to strategic programs and projects to support grid reliability, the Company has shorter term programs to address pockets of the grid where customers have experienced multiple outages. There are two primary programs under Frequent Outage Programs: the Customer Excellence (CE) Program and the Strategic Reliability Improvement Program (SRIP).

The CE program was established to provide rapid solutions to small pockets of customers experiencing poor reliability. These customers are identified as experiencing four sustained outages (SAIFI > 4.0), or nine momentary outages (MAIFI > 9.0) per year. The prioritization method for the CE program relies on Advanced Metering Infrastructure (AMI) data to identify these customers on a rolling 12-month basis to address issues more rapidly than other programs which rely on the annual analysis of reliability events. In addition to reliability event data, the prioritization also includes an evaluation of the time since the area's last tree trim was completed, any other planned work on the circuits, as well as customer complaints.

Upon identification of a circuit that meets the CE prioritization criteria and is selected for construction, the Company conducts a field patrol to assess both equipment and tree conditions impacting reliability. After the patrol, the scope of work is developed for the identified equipment and tree-related problems. In addition to the damaged or failed equipment replacements and tree trimming, the scope of work also includes checking operating equipment to ensure it is functioning properly, conducting fault studies to ensure fuses are properly sized, and installing additional equipment, such as reclosing devices and animal guards, to prevent future outages. On average, the solutions require investments between $60,000 and $80,000 per circuit to implement.

The SRIP Program performs improvements to either portions of a circuit (customer pockets), or entire circuits as appropriate. The primary distinctions between the CE and the SRIP Programs are that circuits are normally selected for the SRIP Program based on both a 12-month and a three-year average circuit SAIDI and SAIFI performance, MPSC complaints, and regional expertise on customer needs. In addition, the scope of work performed under the SRIP Program is more comprehensive, and typically requires investments between $250,000 and $300,000 per circuit to implement.

Q113. What is the Company's Pre-Summer Storm Strengthening (PS3) process?

A113. Beginning in 2021 after a summer with a high number of storms and associated customer outages, the Company began an annual process of analyzing the performance data of all circuits following each summer storm season. This analysis identifies circuits expected to have the worst reliability performance. The PS3 process allocates circuits to multiple programs such as Tree Trim, PTMM, CE, SRIP, and 4.8kV Hardening to ensure they receive improvements before the subsequent summer storm season.

Q114. Has the Company continued the Pre-Summer Storm Strengthening process of identifying circuits that are at higher risk during storms and performing investments on them?

A114. Yes. The Company has continued this process. For 2023, work was performed on 255 circuits within the Frequent Outage (CEMI) Programs and the program plans to perform work on 160 circuits in 2024 and 215 circuits in 2025 (Table 13).

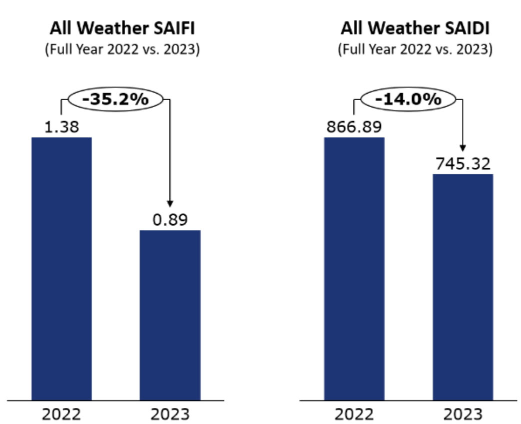
Table 13. Frequent Outage Programs (CEMI) 2023-2025

	2023 Forecast	2024 Forecast	2025 Forecast
CE Circuits	183	100	130
SRIP Circuits	72	60	85
Total Frequent Outage (CEMI) Program Circuits	**255**	**160**	**215**
Capital Investment ($ thousands)	$63,963	$48,050	$62,504

Q115. How do Frequent Outage Programs (CEMI) benefit customers?

A115. Frequent Outage Programs (CEMI) perform circuit improvements that increase electric service reliability for customers who have experienced recent poor reliability. The Company measures the reliability of the circuits selected for the Frequent Outage (CEMI) Program before and after the work is completed (Figures 20 and 21).

Figure 20. Frequent Outage Programs (CEMI) All Weather



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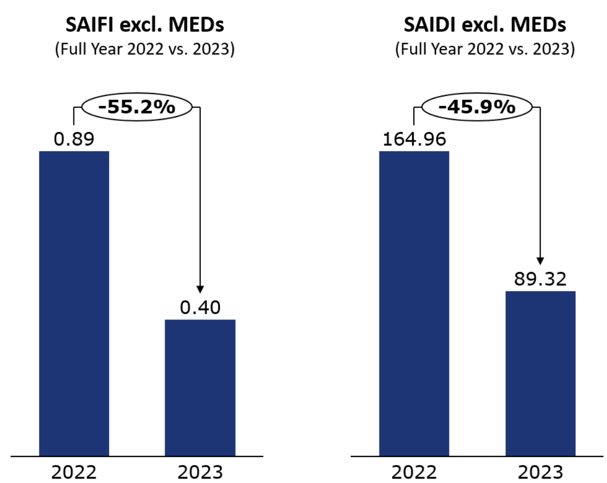
Although weather is variable year to year and can impact comparisons of circuit performance, Figure 20 shows that customers on circuits where Frequent Outage (CEMI) work was performed experienced a 35.2% improvement in All Weather SAIFI and a 14.0% improvement in All Weather SAIDI when comparing 2023 to 2022.

Figure 21. Frequent Outage Programs (CEMI) Excl. MEDs



When excluding the weather impacts of major event days, Figure 21 shows that customers on circuits where Frequent Outage (CEMI) work was performed experienced even greater reliability improvements, a 55.2% improvement in SAIFI excluding MEDs and a 45.9% improvement in SAIDI excluding MEDs when comparing 2023 to 2022.

Q116. How can customers stay informed about Customer Excellence work being performed in their area?

A116. Customers interested in seeing if Customer Excellence work is being performed in their respective area can visit the Company's external website at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456189

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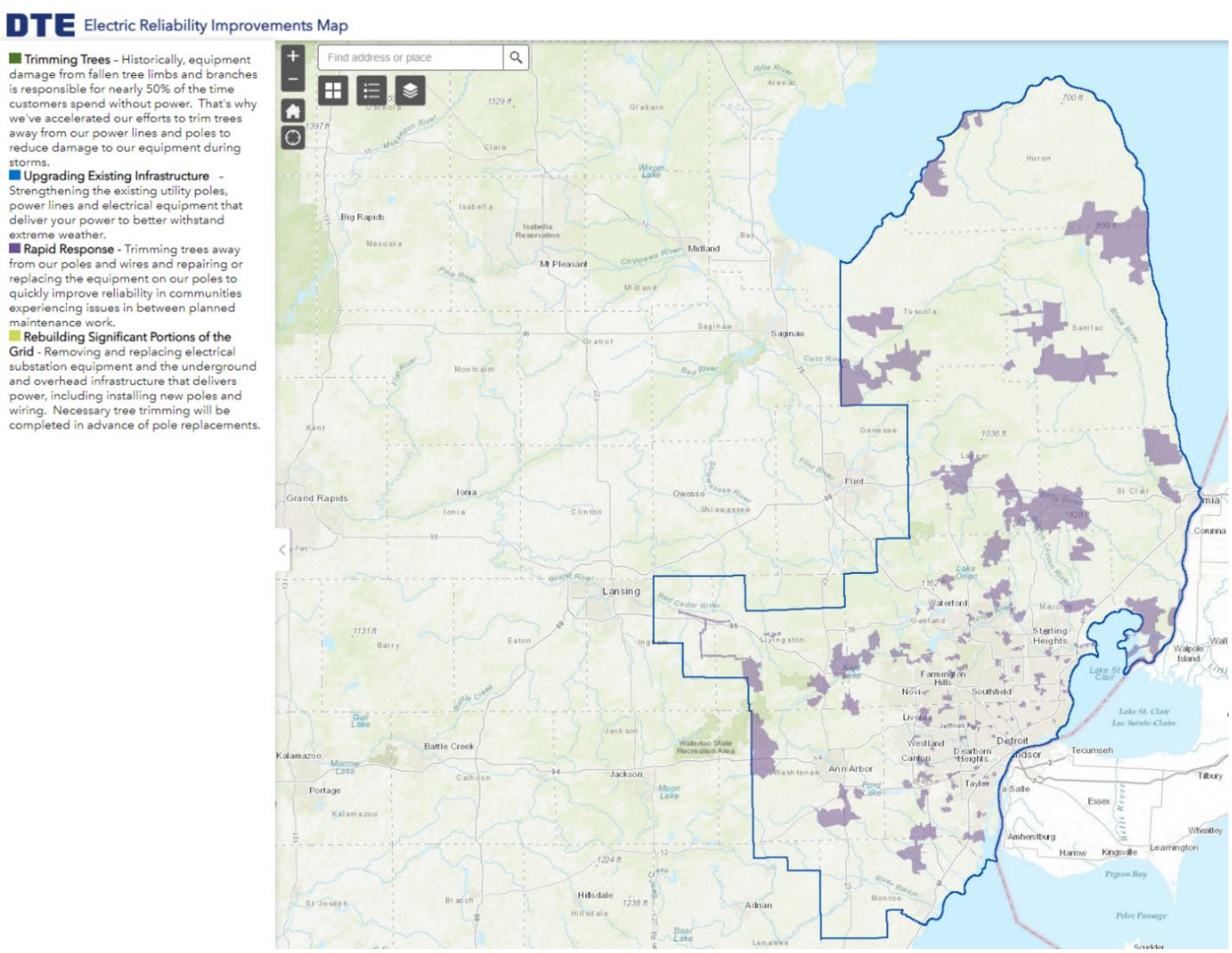
59ce788086e00e. These maps are regularly updated to inform our customers of the reliability work the Company is performing on their behalf, to visually display work completed in the last 6 months, and work scheduled to be completed within the next 12 months. Please note that the Frequent Outage (CEMI) Program is called "Rapid Response" in the map provided on this website. This map also shows Tree Trimming, 4.8kV Hardening and PTMM (called "Upgrading Existing Infrastructure"), and Circuit Conversion (called "Rebuilding Significant Portions of the Grid") A current example of this map showing only the Rapid Response layer can be seen in Figure 22.

Figure 22. Frequent Outage Programs (CEMI) Map



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Cable Replacement Program

Q117. What is Underground (UG) System Cable, and how is it different from Underground Residential Distribution (URD) Cable?

A117. System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System Cable consists of large diameter cable surrounded by various types of insulation, and it is installed underground in vaults and ducts that run between manholes (Figure 23 and 24).

System cable is used for a different purpose than URD cable. System cable is used to transmit higher voltage electricity from substation to substation and to feed primary circuits, while URD cable is designed to provide lower voltage electricity directly to residential neighborhoods. URD is discussed in more detail later in my direct testimony.

Q118. What are the key drivers of the Company's Cable Replacement program?

A118. System cable is a critical component of the distribution and subtransmission system, and while system cable provides high resiliency to storms, system cable failures do happen, and can interrupt a large number of customers for an extended period of time due the longer amount of time it typically takes to locate and replace a failed cable. System cable replacement is an industry standard program to reduce system risk and support reliability.

When a system cable fails, the customers fed from that circuit are typically jumpered to a redundant, or back-up cable, to restore power, and remain on the alternate circuit until the original cable is replaced and back in service. The process to replace the cable includes locating the fault, de-energizing the circuit, cutting the failed section(s), pulling the failed cable out of the conduit, installing new cable, reconnecting (splicing) the new cable to the existing circuit, and re-energizing the circuit. During the time it takes to find and repair the cable, the system has lost redundancy and has increased risk for longer duration outages (if a failure occurs on the redundant circuit). System cable failures can also cause failures in other equipment, including adjacent cables and switchgear, which can then impact an even larger number of customers for a longer period of time. The Company has had an average of 234 system cable failures per year over the last six years (Table 14).

Table 14. System Cable Failures by Cable Type and Year

Failures by Cable Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
PILC	200	193	161	180	202	171
EPR	20	24	24	17	24	37
VCL	11	4	6	5	8	16
Gas	11	9	5	3	3	12
XLPE Post-1990	1	-	-	-	-	-
XLPE Pre-1990	9	3	7	5	1	16
Butyl Rubber	3	2	-	3	2	3
Total Cable Failures	**255**	**235**	**203**	**213**	**240**	**255**

PILC: system cable that is insulated with paper and lead

EPR: system cable that is insulated with ethylene propylene rubber

VCL: system cable insulated with varnished cambric

Gas: system cable that is insulated with nitrogen gas under pressure

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XLPE: system cable that is insulated with cross-linked polyethylene

Butyl Rubber: system cable that is insulated with butyl rubber

During system cable emergent restoration, the crews may experience multiple challenges, which can complicate the work or slow progress on remediation of the failure. In some instances, field crews find underground ducts have collapsed on the cables, making the cable extremely difficult, or in some cases impossible to replace without repairing the ducts (Figure 23). Safety concerns during restoration sometimes cause other intact cables near the failed cable to require a shutdown, meaning they must be de-energized from the substation to make the site safe for work. Other examples of safety concerns include pumping water out of the manholes and managing the wastewater, ensuring the air quality is safe for entry, and often including remediation of contaminants. Once the manholes can be entered safely, the work includes inspecting and testing long stretches of cable to find the fault, and identification of adjacent hazards. Finally, the crews typically pull (Figure 25) and splice the cable as described above, which can be difficult during an emergent failure and restoration situation.

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Figure 23. System Cable – UG Collapsed Duct

Figure 24. System Cable – Cable Inside Manhole

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Figure 25. System Cable Pulling (Removal)

In addition to aging issues, different types of cables are known to have specific failure modes. As an example, XLPE (cross-linked polyethylene) system cable manufactured before 1990 has a design defect that leads to premature insulation breakdown and failures (also called "treeing") and has contributed to switchgear failures. For another example, gas cable which is designed to have cavities within the insulating layer that are filled with nitrogen gas under pressure is an obsolete design, prone to mechanical damage that leads to leaks and failures, as well as costly repairs. As detailed in the DGP, Exhibit A-23, Schedule M8 (as supported by Company Witness Kryscynski), section 4.3.6 on page 46, approximately 63% of the Company's system cable is beyond useful life expectancy. Useful life is a standard industry term that does not represent the actual life of an asset, but rather the age at which an installed asset is expected to require increasing maintenance and reduced performance such that it is often more prudent to replace than to continue to repair and maintain. While age is not the only factor to determine a need for replacement, based on the Company's experience, failure rates increase with age as older cable is typically exposed to more fault currents and has longer water exposure.

Table 15 shows the average age of the different types of the approximately 3,100 miles of system cable that are within the scope of the Cable Replacement Program. The typical useful life expectancy of system cable is 35 to 40 years, although actual useful life varies depending on cable type and field conditions. Based on its asset health assessment for system cable, the Company has determined that approximately 28% of its system cable is at-risk cable and a candidate for replacement, including XLPE cable manufactured before 1990, gas cable, VCL (varnished cambric lead), and paper-insulated-lead cable (PILC) cable greater than 60 years in age. The Company replaces system cable because of the high number of customers who experience an outage when system cable fails without available redundancy and the time it takes to locate and replace the failed system cable.

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Table 15. Cable Types - Average Age and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Pre-1990	XLPE Post-1990	Butyl
Miles	2,069	748	95	47	58	48	31
% of Total Population	66.8%	24.2%	3.1%	1.5%	1.9%	1.5%	1.0%
Average Age	55	18	64	59	40	23	57
Useful Life Expectancy	40	35	40	40	25	40	25

Planned replacement of UG system cable allows the Company to proactively target cable at high risk of failure. This allows for a more strategic, and more efficient process to replace large portions of cable in order to reduce the risk of failures and increase redundancies in a given area.

Q119. What is the scope of the Cable Replacement Program?

A119. The Cable Replacement program exists to identify and replace at-risk system cable. System cable replacement prioritization is based on multiple factors including insulation type, failure history, system impacts, and cable loading. These cables are installed in conduit and spliced together in manholes. When replacing system cable, the Company will also replace failed/collapsed conduit, ducts, and manholes, upgrade substation cable positions, and rebuild cable poles as necessary.

Q120. Was the Cable Replacement Program in the prior rate cases?

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A120. Yes, the Cable Replacement Program was included in Case Nos. U-21297, U-20836, U-20561, and U-20162.

Q121. Did the Commission support investments for the System Cable Replacement program in prior rate cases?

A121. Yes. The Commission stated in its Order for Case No. U-21297,

> "The Commission finds that the company's requested funding should be approved for inclusion in rate base with the Staff's proposed 10% reduction to protect against over-projections. The Commission recognizes that regular maintenance is necessary and that faulty cables should be replaced, and DTE Electric provided evidence that multiple factors are considered in determining where replacements are necessary including vintage, number of failures, and number of affected customers, as well as safety improvements. 3 Tr 531-542, 581-582. … Finally, the Commission disagrees with the ALJ and does not find that it is necessary to separate expenditures by project for this program."

Q122. What is the Company's policy for system cable replacement and how are circuits selected?

A122. The Company's equipment engineers review all system cable on DTEE's underground system and prioritize cable for replacement based on insulation type, quantity of failures, circuit loading, and age of cable. From these factors, a composite score is calculated and the circuits with the highest risk are replaced.

Q123. What sections of cable are replaced by the Cable Replacement Program?

A123. The Cable Replacement Program replaces all sections of cable that are deemed at-risk based on their composite score as discussed above. If there are sections of cable on a circuit that are not deemed to be at-risk, they are not replaced by the program.

Q124. How much system cable was replaced in 2023 and prior years?

A124. The Company replaced 8 miles of system cable in 2023 and has replaced 41.4 miles of system cable over the last six years (Table 16).

Table 16. System Cable Program 2018-2025

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Forecast	2025 Forecast
Cable Miles Replaced	5	10	6	7.4	5	8	10.3	11.3
Capital Investment ($ thousands)	$9,213	$10,945	$12,139	$14,984	$27,746	$22,832	$15,001	$16,501

Q125. How much system cable replacement is planned for 2024-2025?

A125. The Company plans to replace approximately 10 miles in 2024 and 11 miles in 2025 (Table 16).

Q126. How does the Cable Replacement program benefit customers?

A126. Replacing at-risk system cable supports continued reliability for customers. The underground cable system is designed with multiple redundancies to ensure customer reliability. While single cable failures do not normally result in customer outages, if the primary and redundant cables fail at the same time, it results in prolonged outages for customers. Some types of industrial class customers such as hospitals, aren't able

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to tolerate the risk of running with a single cable, and therefore reduce or shut down some functions when this happens. This program reduces overall risk to customers and the grid by proactively replacing cables before they fail, in order to ensure necessary redundancies for this critical part of the system as designed.

Underground Residential Distribution (URD) Replacement Program

Q127. What is Underground Residential Distribution (URD) Cable, and why does the Company replace it?

A127. URD is a specific type of cable designed for underground residential use on the Company's secondary electric system. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or less frequently is installed inside conduit (Figure 26). Because underground repairs can take significant amounts of time to locate and repair when compared to overhead infrastructure, URD systems are typically looped so that there are two paths to feed customers in case one URD cable fails.

Figure 26. URD Cable – Example

As mandated by Michigan Administrative Code R. 460,512, all residential subdivisions in the Company's service territory built since January 1, 1971 are served with URD cable. There are two primary types of URD cable, differentiated by manufacture date. Pre-1985 URD cable has XLPE (non-tree retardant) insulation, while post-1985 the insulation has TR-XLPE (tree-retardant) insulation. In cable insulation, "treeing" refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure. There are nearly 11,000 total miles of URD cable on the system, with approximately 2,068 miles (24%) being pre-1985 non-tree retardant vintage (Table 17).

Table 17. URD Cable Types - Average Age and Life Expectancy

URD Type	Pre-1985	1985+
URD Cable Miles	2,068	8,512
% of Total Population	24%	76%
Average Age (Years)	46	20
Life Expectancy (Years)	40	40

In addition to failures caused by treeing described above, in general, the rate of URD cable failures increases with the age of the cable, and the rate further increases once a cable experiences its first failure. Manufacturer expected useful life for URD cable is approximately 40 years. Useful life is a standard industry term that does not represent the actual life of an asset, but rather the age at which an installed asset is expected to experience increasing failure rates and reduced performance such that it is often more prudent to replace than to continue to repair and maintain. For the six-year period from 2018 through 2023, there were on average approximately 930 URD cable failures per year as seen in Table 18.

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Table 18. URD Cable Failures

	2018	2019	2020	2021	2022	2023	2018-2023 Average
URD Cable Failures	1,039	755	1,036	986	900	864	**930**

Q128. What is the scope of the URD Replacement Program?

A128. There are two primary types of work performed by the URD Replacement Program: prioritizing and replacing existing URD cable and replacing live-front UG transformers (described below) with dead-front UG transformers.

The program prioritizes and replaces URD cable based on multiple factors including number of failures on the circuit, and number of customers affected by those failures, and URD cable type. The program also includes the replacement of live-front transformers with dead-front transformers. Some URD cable is fed from live-front transformers, which is an obsolete design that does not include protective coverings over energized equipment, and therefore poses a potential safety risk to crews in the field while performing operating work once the external transformer covering is removed.

Single URD cable faults (outages) are typically restored quickly after an UG splicing crew arrives and bypasses the URD failure by back feeding the customers from another source on the URD loop. However, once the customers are restored, there is follow-up work required to locate and repair the URD fault that caused the original outage, and to restore the system to normal operating conditions. This follow-up work is called an open loop. These open loops leave the system without redundancy, such that if a second URD failure occurs on the same URD loop, a new long-duration outage (4+ hours) will result for the customers as there is no redundancy to back feed the customers as described above, while replacing the failed URD cable. Second URD failures within six months of the original failure have occurred on average 49 times annually over the last six years (Table 19).

Table 19. URD Double Cable Failures Within 6 months

	2018	2019	2020	2021	2022	2023	2018-2023 Average
URD Double Cable Failures	32	18	37	59	32	115	**49**

In addition, planned replacements are more cost effective than repairing failures, as the Company can strategically plan to replace entire circuits of URD and live-front transformers, rather than reactively fixing smaller sections of the circuit following a failure.

Table 20. URD Double Cable Failure Outage Data

URD Double Failures w/in 6 months	2018	2019	2020	2021	2022	2023
Customers Impacted	1,491	965	1,923	2,542	1,749	5,415
Outage Duration	137 hours	85 hours	182 hours	370 hours	187 hours	791 hours
Average Outage Duration	4.3 hours	4.7 hours	4.9 hours	6.3 hours	5.9 hours	6.9 hours
Total Customer Outage Minutes	356,604	265,151	484,347	837,078	683,363	2,574,899

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URD Replacement Program investments include design for the following year's program, remediation of identified hazards to streamline execution of the following year's plan, the replacement of the targeted URD miles, and the replacement of live-front transformers with dead-front transformers (Figures 27 and 28).

Figure 27. Live-front UG Transformer

Figure 28. Dead-front UG Transformer

Q129. Was the URD Replacement Program included in prior rate cases?

A129. Yes, the URD Replacement Program was included in Case Nos. U-20162, U-20561, U-20836, and U-21297.

Q130. Were URD Replacement Program investments supported in prior rate cases?

A130. Yes. The Commission stated in its Order for Case No. U-21297,

> "The Commission finds that the company's requested funding should be approved for inclusion in rate base with the Staff's proposed 10% reduction to protect against over-projections. The Commission recognizes that regular maintenance is necessary and that faulty cables should be replaced, and DTE Electric provided evidence that multiple factors are considered in determining

where replacements are necessary including vintage, number of failures, and number of affected customers, as well as safety improvements. 3 Tr 531-542, 581-582. … Finally, the Commission disagrees with the ALJ and does not find that it is necessary to separate expenditures by project for this program."

Q131. How much URD cable was replaced in 2023?

A131. The URD Replacement Program replaced 75.3 miles of URD cable in 2023 and has replaced approximately 223 miles of URD cable from 2018-2023 (Table 21).

Table 21. URD Cable Miles and Transformers Replaced 2018-2023

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
URD Miles Replaced	71.6	3.6	3.6	24.5	44.7	75.3
Live-front Transformers Replaced	-	-	1	63	110	111
Capital Investment ($ thousands)	$10,915	$362	$964	$4,705	$7,043	$13,750

Q132. Why is the planned investment in Exhibit A-12, Schedule B5.4 for URD Replacement shown as $0 in 2024 and 2025?

A132. Because the Commission approved the Company's Infrastructure Recovery Mechanism (IRM) in Case No. U-21297, and URD Replacement investments are addressed through that mechanism, the investments for URD Replacement have been moved from Exhibit A-12, Schedule B5.4 to the IRM Exhibit A-33 Schedule X1 for 2024 and 2025.

Q133. How does the URD Cable Replacement Program benefit customers?

A133. The program will improve reliability by reducing the number of residential customer interruptions experienced by URD cable failures in the areas in which this program has completed work. This will also benefit customers by reducing the risk of multiple failures and long duration outages due to pre-existing open loops as described above.

Breaker Replacement Program

Q134. What are substation breakers and substation reclosers, and what purpose do they serve?

A134. The path electricity travels across the system can be subjected to interruptions due to a variety of factors (e.g., a tree falling on an overhead electrical line), which can cause outages and potentially dangerous situations for customers and employees. Electrical switches, most commonly breakers or reclosers, are in place at points along the network to recognize and isolate these interruptions (also known as electrical faults) from the rest of the distribution system. These switches help to minimize equipment damage from electrical faults and allow power to continue flowing to as many customers as possible while restoration is completed for the damaged circuits.

At the subtransmission and distribution levels, there are large breakers (switches) at stations and substations that interrupt the current flow when a fault is detected to minimize equipment damage and to isolate the faulted equipment from the rest of the system.

Downstream from the substation breakers, located on distribution circuits, are substation reclosers. Substation reclosers perform similarly to a breaker. When they detect faults, they open and isolate the interruption to a smaller area, impacting fewer customers. Substation reclosers can prevent the substation breaker from opening, avoiding a larger circuit level outage. Additionally, these reclosers can be used to tie two circuits together so that, in the event of an outage, one circuit can provide power to the other. Reclosers have a key role to play in improving reliability and are the foundation of the automation program.

Q135. What is included in the Breaker Replacement Program?

A135. The Company has approximately 6,000 breakers on the electrical distribution and subtransmission systems with approximately 60% of those breakers at an age beyond their life expectancy. The breakers included in the replacement program have an obsolete design, typically utilizing insulation oil for fault extinguishing.

Breakers replaced by the Breaker Replacement Program are classified into four categories: distribution breakers, subtransmission breakers, H-breakers, and substation reclosers. In addition to replacing breakers, the program also replaces relays and controls to make the equipment SCADA-ready. SCADA (supervisory control and data acquisition) utilization on equipment, will provide the Electric System Operations Center (ESOC) greater visibility to system performance, which will allow ESOC personnel to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits during both planned and unplanned outages.

Q136. Was the Breaker Replacement Program in the prior rate cases?

A136. Yes, the Breaker Replacement Program was included in Case Nos. U-20162, U-20561, U-20836, and U-21297.

Q137. Were Breaker Replacement Program investments supported in prior rate cases?

A137. Yes. The Commission stated in its Order for Case No. U-21297,

> "The Commission finds that the replacement of obsolete circuit breakers is the type of work, like the removal of arc wire, that is necessary and lends itself to few alternatives. The Commission disagrees with the ALJ and approves DTE Electric's requested funding for inclusion in rate base but adopts the Staff's proposed 10% reduction to the company's test year request as a check on the potential for over-projections. The company provided evidence that 60% of breakers in the distribution and subtransmission systems (including substation reclosers) are beyond their life expectancy. DTE Electric provided the criteria used for selecting which breakers to replace and indicated that it plans to replace 35 breakers in 2023 and 36 in 2024. 3 Tr 543-544. While the evidentiary showing could have been more robust, the Commission believes that this is important work that needs to be done and approves the requested funding with the 10% reduction."

Q138. What are the customer benefits from the Breaker Replacement Program?

A138. The benefits of breaker replacement and enhanced relaying and controls include enhanced safety, reduction of substation outage risk caused by breaker failures, improved customer reliability, reduction in reactive expenditures due to breaker failures, added ability to utilize SCADA controls, and the reduction of outage duration due to enhanced fault location and event analysis provided by SCADA capability.

Table 22. Breaker Failures 2019-2023

Installation Decade	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	Total
Unknown	-	1	-	-	-	**1**
1930s	5	1	3	1	1	**11**
1940s	4	2	2	8	2	**18**
1950s	36	38	35	55	48	**212**
1960s	17	24	7	15	9	**72**
1970s	33	19	16	29	17	**114**
1980s	13	10	7	7	17	**54**
1990s	27	34	22	34	26	**143**
2000s	14	6	6	10	21	**57**
2010s	6	6	32	1	19	**64**
2020s	-	-	-	-	1	**1**
Total Breakers Failures	**155**	**141**	**130**	**160**	**161**	**747**

Q139. How are breakers selected for replacement?

A139. The candidates for breaker replacements are chosen by the Company's equipment engineers who review all breakers on the system. Breakers are prioritized based on the following criteria:

- Breakers with known performance issues;
- Breakers with no or limited availability of spare parts;
- Breakers with insulation oil for fault interrupting medium which is flammable; and
- Breakers that require short inspection cycles compared to the rest of the breakers on our system.

Q140. Can you provide a specific example of an obsolete breaker type that is prioritized for replacement by the Breaker Replacement Program?

A140. Yes. H-breakers are an obsolete oil breaker design, amongst the oldest in the utility industry, dating back to at least the 1920s. H-breakers are no longer manufactured, and replacement parts are not available in the market for them. The Company has replaced twenty-six obsolete H-breakers with modern breakers over the last six years.

Q141. How many Breakers have been replaced through the Breaker Replacement program in 2023 and prior years?

A141. Please see Table 23.

Table 23. Breakers Replaced 2018-2023

Breaker Type	2018	2019	2020	2021	2022	2023
Distribution Breakers	31	19	20	22	15	16
Subtransmission Breakers	14	9	7	4	12	6
H-Breakers	5	7	6	3	2	3
Substation Reclosers	6	7	4	10	5	4
Total Breakers	**56**	**42**	**37**	**39**	**34**	**29**
Capital Investment ($ thousands)	$9,919	$9,148	$10,931	$17,365	$14,415	$13,161

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Q142. Why is the forecasted amount in Exhibit A-12, Schedule B5.4 for Breaker Replacement $0 in 2024 and 2025?

A142. Because the Commission approved the Company's Infrastructure Recovery Mechanism (IRM) in Case No. U-21297, and URD Replacement investments are addressed through that mechanism, the investments for Breaker Replacement have been moved from Exhibit A-12, Schedule B5.4 to the IRM Exhibit A-33 Schedule X1.

Mobile Fleet Program

Q143. What is the Mobile Fleet Program?

A143. These investments expand the fleet of mobile generation which is used to quickly restore power to customers during major events such as substation failures. These assets include portable generators, portable switchgear, portable substations, portable ISO equipment, portable poles, energy storage trailers and the controls that allow these assets to work together cohesively during planned and emergency events. This mobile equipment offers multiple operational benefits including decreasing restoration time during substation failures for substation load that can't be fed from adjacent substations/circuits, supporting substations on a single contingency to avoid outages, and providing the ability to facilitate the repairs of the failed equipment inside the substation while customers remain energized. Mobile Fleet Program equipment is also used to support customers during planned construction work when field crews must deenergize electric equipment to allow for work to be performed in a safe manner.

Figure 29. Portable Substation (left) & Mobile Generator (right)

Q144. How does the Mobile Fleet Program benefit customers?

A144. Since the beginning of 2022, DTEE has experienced 96 major events on the system. These events have caused loss of power for anywhere from a few hundred customers to over 10,000 customers. One example of a major event in 2023 occurred at Snover substation, a single transformer, two circuit substation. The single substation transformer failed, resulting in loss of load for nearly 1,100 customers for approximately 13 hours. The load of the circuits could not be transferred to neighboring circuits due to the configuration of adjacent DTEE circuits and because the other adjacent circuits are owned by other electric providers. The Company's short-term solution was to deploy portable distributed generators to serve the load of the two circuits. The medium-term solution required the Company to install a portable substation while permanent repairs were made at Snover substation. This example highlights both the significant challenges to addressing a major event failure and the important role the Mobile Fleet Program plays in restoration of service to customers.

In addition, the mobile fleet equipment allows the Company to perform planned work, such as preventative maintenance on single-tap substations, without requiring customers to experience an outage while the work is being performed.

Q145. What Mobile Fleet Program equipment is the Company planning to purchase in this instant case?

A145. The Company began building the infrastructure around the engine and generator for PDG1 (Portable Distributed Generator), constructed small switching trailers, performed controls work on portable switchgear, and installed controls enhancement on PDG3 units in 2023.

The Company plans to complete the building of PDG1, perform the integration of portable generator controls to enhance functionality, complete portable switchgear, and install synchrophasor time-based trips for generators in 2024.

The Company plans to perform integration of portable controls, purchase of additional connection skids, convert hybrid DC generator to a low carbon generator, and phase balance controls in 2025.

Pontiac Vaults

Q146. What is the current state of the Company's infrastructure that provides service to the City of Pontiac?

A146. DTEE acquired the electrical system that services the main portion of the City of Pontiac in the 1980s from Consumers Energy. Pontiac is served by an 8.3kV system fed by four substations (Barlett, Paddock, Rapid Street, and Stockwell) and 18 distribution circuits. This portion of the system is surrounded entirely by 13.2kV circuits, so that in the event of a major failure, the Company is unable to quickly restore customers by transferring load to adjacent DTEE circuits.

The 8.3kV system uses a non-standard voltage that the Company does not use in any other area of its service territory and is an obsolete system. Replacement parts are no longer available for 8.3kV breakers and other substation equipment due to their obsolescence, leading to extended customer interruptions, and leaving the system in an abnormal state for longer durations when work must be completed (preventative or reactive). Additionally, the City of Pontiac has seen a gradual increase in load demand over the past several years. In response to these factors, the Company has created a plan to convert the four 8.3kV substations (and corresponding distribution circuits) to 13.2kV, as detailed in Company Witness Deol's testimony.

The Pontiac 8.3kV system includes underground vaults which contain electrical equipment, such as sectionalizing equipment and service transformers, since the footprint necessary for this infrastructure is not available above ground. These vaults primarily house the equipment that provides service to the downtown business district, which includes hospitals and City of Pontiac official buildings.

Q147. What is included in the Pontiac Vaults program?

A147. The Pontiac Vault Program performs upgrades on the existing underground equipment with modern equipment that is submersible and arc sealed. This work includes replacing damaged vaults, replacing at-risk and end-of-life equipment in the vaults, replacing 7 miles of existing non-standard cable, and installing SCADA monitoring equipment.

Q148. How does the Pontiac Vault Program benefit customers?

A148. The customers benefit from this investment because it is an integral part of the greater 8.3kV conversion initiative that will improve reliability, allow for faster outage restoration, and increase electric capacity available to serve the City of Pontiac. Additionally, the Pontiac Vaults program replaces at-risk, aging, non-standard equipment that poses a reliability risk to downtown Pontiac and a safety hazard to the Company operators and to the public in the vicinity of the vaults.

Q149. What work is the Company planning to complete in this instant case?

A149. In 2023, the Company completed the following construction: Installed conduit and cable, made appropriate repairs to the vault structures, installed a light post and radio, and the loads transfer to energize the Cesar-Chavez Vault; and installed cable between the Huron Vault and the -3 transformer.

<u>40kV: Automatic Pole-Top Switch</u>

Q150. What are Automatic Pole-Top Switches (APTS)?

A150. The function of the APTS is to sectionalize, isolate, or connect portions of the subtransmission system. Failure of one of these switches has the potential to interrupt thousands of customers or result in significant operational constraints. The Company has identified APTS currently installed in the distribution system that are no longer working properly or at risk of failure, and where replacement parts are no longer available due to obsolescence.

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Q151. How does the 40kV: APTS Program benefit customers?

A151. When customer outages occur on the system, if one of these APTS devices is not working properly, it can cause an extended outage for thousands of customers. This program ensures the APTS in the field will operate properly when necessary, so that these devices can reduce the size and impact of multiple customer outages and increase reliability the customers experience.

Q152. How many APTS is the Company planning to replace for the investments included in the instant case?

A152. In 2023, the Company replaced 10 APTS. The Company plans to replace 12 APTS in both 2024 and 2025.

<u>Disconnect and Switcher Replacement</u>

Q153. What are Disconnects and Switchers?

A153. Subtransmission disconnect switches ("Disconnects") are used to sectionalize and provide isolation points on the electrical system for operational reasons and/or to enable service and maintenance. Failures of disconnects during operation, when operators attempt to open or close a disconnect manually, can lead to safety concerns, reduce system operability, and force additional equipment to be taken out of service to allow critical work to continue.

Circuit switchers ("Switchers") connect the transmission system (120kV) and the subtransmission system (40kV) to the primary side of a substation power transformer. The purpose of circuit switchers is to protect substation equipment from damage caused

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by excess fault current. Circuit switchers are a smaller, less expensive alternative to circuit breakers. The Company uses circuit switchers exclusively for transformer protection when performing new construction except in situations that require breakers, such as when reclosing function is required, and if the available fault current exceeds the capacity of switchers.

Q154. How does the Disconnects and Switchers Program benefit customers?

A154. The Company replaces disconnects and switchers that have been identified as at-risk, and/or have been identified as being undersized compared to the current fault currents, making them no longer capable of providing proper protection to transformers. These replacements help to protect the Company's operators while manually operating the equipment, allow the Company to sectionalize the system (thus reducing the size and impact of customer outages) when performing work, and to protect the other substation equipment from damage when excess fault current occurs.

Q155. How many disconnects and switchers is the Company planning to replace in this instant case?

A155. The Company replaced 24 disconnects in 2023 and plans to replace 23 disconnects in both 2024 and 2025.

The Company replaced 4 switchers in 2023 and plans to replace 6 switchers in both 2024 and 2025.

<u>Steel Pole Highway Crossings</u>

Q156. What is the Steel Pole Highway Crossings Program?

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A156. The Company has experienced incidents where wood poles have failed and fallen into highways and caused shutdowns. The Steel Pole Highway Crossing program identifies current wood pole locations where the overhead wire crosses a highway and have a high risk of failure, and replaces these at-risk wood poles with steel poles to reduce the likelihood of pole failures that can impact traffic and public safety and cause customer outages.

Q157. How does the Steel Pole Highway Crossings Program benefit customers?

A157. This program was developed to replace high-risk wood poles with steel poles, primarily to reduce the risk of overhead equipment falling and disrupting the highway system of southeastern Michigan, however this also provides an ancillary reliability benefit as failed poles can result in customer outages.

Q158. How many Steel Pole Highway Crossings does the Company plan to complete in this instant case?

A158. In 2023, the Company installed 4 Steel Pole Highway Crossings, and plans to complete 6 crossings in both 2024 and 2025.

Batteries and Chargers Replacement Program

Q159. What are Batteries and Chargers?

A159. The Company's substations utilize batteries and chargers to provide reliable power necessary to trip equipment such as breakers during fault conditions. Failures of batteries and chargers would result in significantly longer duration faults, greater damage to system equipment, larger outages, and increased hazards due to the inability to clear electrical faults.

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Q160. How does the Batteries and Chargers Program benefit customers?

A160. Batteries and chargers have a finite lifespan and eventually require replacement with new units. The Company identifies batteries and chargers that are at-risk of failure and at end of useful life and selects them for replacement. These devices ensure that substation equipment is protected during fault conditions and can continue to operate properly to maintain reliability.

Q161. How many Batteries and Chargers does the Company plan to replace in this instant case?

A161. In 2023, the Company replaced 54 batteries and 30 chargers. The Company plans to replace 48 batteries and 27 chargers in both 2024 and 2025.

SCADA Pole-Top Device Replacement

Q162. What are SCADA Pole-Top Devices?

A162. SCADA-enabled pole-top devices, such as overhead three-phase reclosers, are sectionalizing devices that are located at key points on overhead distribution circuits. These devices act like a circuit breaker, opening under detection of high current due to a downstream fault, such as a tree branch across two phases. These devices allow the Electric System Operations Center (ESOC) to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits during both planned and unplanned outages.

Q163. How does replacing SCADA Pole-Top Devices benefit customers?

A163. This program replaces devices that have experienced high rates of failure such as Eaton Form 3 reclosers and Bridges pole-top switches (PTS). Failure of these devices reduces system operability, thus increasing the amount of extended duration outages for customers. Replacing these identified devices allows the ESOC to operate the system more effectively, reducing the number and duration of outages experienced by customers.

Q164. How many SCADA Pole-Top Devices does the Company plan to replace in this instant case?

A164. In 2023, the Company replaced 19 SCADA pole-top devices. The Company plans to replace 20 SCADA pole-top devices in both 2024 and in 2025.

<u>Substation Regulator Replacement</u>

Q165. What are Substation Regulators?

A165. Substation regulators are devices that ensure voltages stay within the normal ranges for which Company and customer equipment is rated to perform. Voltage regulation is critical to maintaining the health of electric equipment and helps to maintain the service life of this equipment.

Q166. How does replacing Substation Regulators benefit customers?

A166. Voltage regulation is essential to maintain the health and operability of electrical equipment and prevents the premature damage and failure of this equipment, thus reducing outages customers experience.

Q167. How many Substation Regulators does the Company plan to replace in this instant case?

A167. In 2023, the Company replaced 4 substation regulators. The Company plans to replace 3 substation regulators in both 2024 and 2025.

<u>Portable Generators</u>

Q168. What is the Portable Generator Program?

A168. The Portable Generator Program is an investment the Company is undertaking to help reduce the length of extended outages to single customers during storm events. In short, the Company has purchased portable generators that can be dispatched and serviced to single customers to help energize critical devices such as refrigerators, freezers, personal medical devices, and sump pumps in the event they are expected to be out of service for an extended period during large storms. This program is discussed in more detail in Company Witness Hill's testimony.

Q169. Does this complete your direct testimony?

A169. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEEGAN O. FARRELL

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Keegan O. Farrell (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company) as the Manager of Demand Response.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Michigan State University with a Bachelor of Arts Degree in Communication. In addition, I received a Master of Science Degree in Decision Technologies from the University of North Texas.

Q4. What is your work experience?

A4. From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth, Texas where I held positions of increasing responsibility, ultimately serving as a Decision Support Analyst. In this role, I was responsible for assisting with calculating reservoir economics, monitoring daily oil and natural gas production, and overseeing the compliance and emission calculations for the Environmental Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I joined DTE Energy as a Senior Business Financial Analyst – Load Research. In 2014, I was promoted to Principal Financial Analyst – Load Research. In this position, I was responsible for developing and implementing statistical sampling programs used to evaluate customer class usage characteristics, developing

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allocation schedules for use in cost-of-service studies and rate design, and for measuring and evaluating demand response programs offered by the Company. In 2018, I accepted the position of Supervisor Program Management – Demand Response (DR).

Q5. What is your current position?

A5. In 2021 I was promoted to Manager of DR. In this position I am responsible for overseeing DTE Electric's DR portfolio, which includes short- and long-term strategic development, marketing and management of DR programs and pilots.

Q6. Do you hold any certifications or are you a member of any professional organizations?

A6. Yes. I am the course coordinator for the Association of Edison Illuminating Companies (AEIC) Fundamentals for Load Data Analysis course. In addition, I represent DTE Energy on the board of the Peak Load Management Alliance (PLMA).

Q7. Have you received industry related training?

A7. Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I have also attended various courses at Michigan State University Institute of Public Utilities Annual Regulatory Studies Program as well as the Demand Response Fundamentals and Evolution Course presented by the PLMA.

Q8. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A8. Yes. I have sponsored testimony and exhibits before the MPSC in the following DTE Electric cases:

Case No.	Description
U-18014	DTE Electric 2016 General Rate Case
U-18255	DTE Electric 2017 General Rate Case
U-20162	DTE Electric 2018 General Rate Case
U-20471	DTE Electric 2019 Integrated Resource Plan (IRP)
U-20521	DTE Electric 2017-2018 Demand Response Reconciliation Case
U-20793	DTE Electric 2019 Demand Response Reconciliation Case
U-21044	DTE Electric 2020 Demand Response Reconciliation Case
U-20836	DTE Electric 2022 General Rate Case
U-21242	DTE Electric 2021 Demand Response Reconciliation
U-21193	DTE Electric 2022 IRP
U-21297	DTE Electric 2023 General Rate Case

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Purpose of Testimony

Q9. What is the purpose of your testimony?

A9. The purpose of my direct testimony is to discuss the demand response efforts that DTE Electric is conducting and provide support for the expenditures and activities associated with the continuation of programs and pilots, as well as briefly discuss the evolving DR landscape. I also discuss the development, future plans, and related expenditures associated with the DTE Insight Program.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am sponsoring in whole, or in part, the following exhibits:

Exhibit	Schedule	Description
A-12	B5.6	Capital Expenditures – Demand Response Portfolio and DTE Insight
A-12	B5.6.1	C&I Battery Storage Pilot Document
A-12	B5.6.2	Residential Generator Pilot Document
A-12	B5.6.3	Vehicle-to-Home Pilot Document
A-12	B5.6.4	Smart Charge Pilot Document
A-13	C5.9	Demonstrating and Selling Expenses-DR (line 9)

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

Q12. How is your testimony organized?

A12. My testimony consists of the following seven parts:

Part I Demand Response Overview

Part II	Regulatory Framework
Part III	DR Portfolio
Part IV	DR Portfolio Investments
Part V	Evolving DR Landscape
Part VI	DTE Insight Program

Part I: Demand Response Overview

Q13. What is the purpose of Demand Response (DR)?

A13. DR is designed to reduce or shift enrolled customers' energy usage during periods of high demand. DR programs provide an opportunity for customers to reduce or shift their electricity usage during periods of high energy demand in response to rates or other forms of incentives.

Q14. What are the benefits to customers for participating in DR programs?

A14. DR programs allow electric customers to play a role in the operation of the electric grid and support the clean energy transition. Customers participating in DR programs or tariffs can benefit from lower bills and/or incentives when utilizing these programs. All customers, whether they participate or not, benefit from the cost savings that DR provides. This is because as the demand for power decreases, less efficient or more expensive forms of generation are not needed.

Q15. What are the benefits of DR to the utility?

A15. The reduction or shift in customer usage from DR programs can provide value to the utility by reducing the need for additional generation, resulting in lower energy costs and supporting the Company's generation transformation. If DR programs are less costly than other capacity resources, the utility and all customers can benefit from displacing or deferring the need for new generation resources. In addition, reducing electricity usage when demand is the highest can result in lower wholesale energy prices.

Part II: Regulatory Framework

Q16. What is the regulatory framework adopted by the Commission to approve, recover, and reconcile expenditures in the Company's DR portfolio?

A16. In the September 15, 2017, Order in Case No. U-18369, the Commission approved a 'three-phase' approach for the approval, recovery, and reconciliation of DR expenditures. In the first phase, DR proposals are evaluated in the context of an integrated resource plan (IRP). In the second phase, DR plans that were approved as part of the IRP are considered pre-approved and the associated costs are included in rates in the utility's future general rate cases. The utility can also propose changes or modifications to DR programs or pilots at this time. The IRP DR proposed programs and pilots, as well as any changes, are then evaluated and approved in rate cases and can be considered for inclusion in the next IRP. The third phase involves a reconciliation of DR costs, participation rates, and demand savings achieved on an annual basis. The Commission also stated that during the reconciliation proceedings, actual capital spending in the examination period will be reconciled against the amount approved in the IRP and recovered in a rate case while Operation and Maintenance ("O&M") spending will be reconciled against the amount approved and recovered in a general rate case.

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In addition, the Company can earn a financial incentive through a financial incentive mechanism (FIM) calculated in each annual reconciliation case. The FIM methodology was agreed upon in the settlement of the 2019 DR Reconciliation (Case No. U-20793).

Q17. What DR capital costs were pre-approved through settlement in the Company's most recent IRP?

A17. Table 1 shows the capital costs that were pre-approved through settlement in the Company's last IRP Order, Case No. U-21193, issued July 26, 2023.

Table 1 U-21193 Pre-approved DR Capital Expenditures

Program	2024	2025
CoolCurrents	$500,000	$500,000
SmartCurrents	$2,500,000	$2,500,000
Commercial & Industrial Dashboard	$350,000	$350,000
Interruptible Water Heating	$1,000,000	$1,000,000
Total	$4,350,000	$4,350,000

Part III. DR Portfolio

Q18. Could you describe the Company's current DR portfolio?

A18. Yes. DTE Electric develops and manages its DR programs offering customers a range of options consisting of products, customer incentives, tariff structures, and education based on their profiles and willingness to curtail or shift energy usage during peak hours. As part of the development process, the DR organization evaluates customer behavior, program acceptance and validates technologies that can deliver benefits to its customers.

The Company's current DR portfolio is made up of eleven tariffs and programs and four pilots that are available to residential, commercial and industrial customers. The goal of the Company's DR portfolio is to deliver measurable peak demand reduction by effectively engaging customers to manage and reduce or shift their energy consumption.

Q19. What measurable value does the DR portfolio provide?

A19. The Company currently registers DR as Load Modifying Resources (LMR) at MISO and receives capacity credit for its established DR portfolio.

Q20. What programs and tariffs are included in the Company's current DR portfolio?

A20. The Company's DR portfolio is made up of CoolCurrents™, SmartCurrents™, Smart Savers, Interruptible Water Heating, Dynamic Peak Pricing (DPP) and multiple interruptible tariff rates for Commercial and Industrial (C&I) customers. The participants in the DR programs or on the tariffs receive a discounted rate or incentive in exchange for reducing their load during DR events.

Q21. What is a DR event?

A21. A DR Event is a period of high energy demand when programs are activated to relieve stress on the grid.

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Q22. What is the CoolCurrents Program?

A22. CoolCurrents is the program name for the Interruptible Space Conditioning tariff (Rate D1.1) that is available to residential and commercial customers. Customers who enroll in CoolCurrents are equipped with a direct load control device (LCD) on their air conditioning unit(s) or central heat pump that allows the Company to cycle the associated appliance in exchange for a discounted rate. The cycling of the appliance is limited to no more than eight hours in any 24-hour period and events can be called year-round in any of the four MISO seasons.

Q23. What is the SmartCurrents Program?

A23. The SmartCurrents Program, commonly referred to as the Programmable Communicating Thermostat (PCT) Program, is a DR offering where residential and commercial customers receive a free ecobee premium thermostat. By enrolling in SmartCurrents and installing their free thermostat, customers agree to allow the Company to adjust the thermostat setpoint by up to four degrees during SmartCurrents events. SmartCurrents events can occur on non-holiday weekdays between the hours of 12:00 pm and 8:00 pm, can last no more than four hours and are limited to 64 total hours each calendar year, and available year-round.

Q24. What is the Smart Savers program?

A24. The Smart Savers program, which is a Bring Your Own Device (BYOD) program, is available to residential and commercial customers who have an existing and eligible PCT installed at their residence or business. In this program, customers enroll their eligible thermostat in the program and agree to let the Company adjust the setpoint on the thermostat up to four degrees during Smart Savers events. Smart

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Savers events last no more than four hours and can be called between 12:00 pm and 8:00 pm on non-holiday weekdays. The Smart Savers season runs from June 1st through September 30th and events are limited to 56 total hours annually.

Q25. What is the Interruptible Water Heating rate?

A25. The Interruptible Water Heating rate (D5) is available to both residential and commercial customers that use hot water for sanitary purposes or other uses subject to the approval of the Company. An LCD is installed at the customer's location that turns off the heating element of the water heater for up to four hours in any 24-hour period during any MISO season. Participating customers receive a discounted rate on the associated water heating usage.

Q26. What is the DPP rate?

A26. The DPP rate (D1.8) is a rate that is offered to residential and commercial customers. It is a three-tiered Time of Use rate (On-Peak, Mid-Peak, and Off-Peak), with a critical peak pricing (CPP) rate component. During a CPP event, which are available year-round in any of the four MISO seasons, the price per kilowatt of electricity increases to $0.95 per kilowatt hour. CPP events occur between 3:00 pm and 7:00 pm on non-holiday weekdays and are limited to no more than 56 hours per year.

Q27. What additional interruptible tariffs does the Company offer to C&I customers to promote participation in demand response?

A27. The Company offers C&I customers six tariffs at a discounted rate in exchange for agreeing to interrupt a portion of their electric load during DR events. Unless otherwise noted, these tariffs are available for interruption year-round in any of the four MISO seasons. The tariffs that are available to C&I customers are as listed:

1. Interruptible General Service Rate (D3.3): Commercial secondary customers can elect to have separately metered service that is subject to interruption or establish a portion of their load as firm through the product protection feature. This rate is not available to customers whose loads are primarily off-peak. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load.
2. Interruptible Supply Base Service Rate (D8): Primary voltage customers who desire separately metered service for a specified quantity of demonstrated interruptible load of not less than 50 kW at a single location can take service under this rate. Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads will lead to a capacity deficiency.
3. Alternative Electric Metal Melting (Rider 1.1): Customers who operate electric furnaces for the reduction of metallic ores and/or electric use consumed in holding operations who provide special circuits can have that load separately metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.
4. Electric Process Heat (Rider 1.2): Customers who use electric heat as an integral manufacturing process, or electricity as an integral part of anodizing, plating, or a coating process and who provide special circuits can have that load separately

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metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.

5. Interruptible Supply Rider (Rider 10): Rider 10 allows customers to elect the amount of interruption they are willing to take under a separate meter. Program participation is capped at a total of 650 MW of enrolled load. Rider 10 is designed for customers of greater than 50 MW at a single location, although at the Company's discretion, and with available capacity, the minimum site requirements can be waived. The Company may order an interruption to maintain system integrity.
6. Capacity Release (Rider 12): Customers are provided a capacity release payment by subscribing at least 100 kW of load per site location for interruption. The Company may order an interruption to maintain system integrity. The program is only available during the MISO summer season from June 1 – August 31 although the Company is evaluating customer reception for Rider 12 to be made available for the other seasons as well.

Q28. How much capacity does the Company's existing DR portfolio account for in meeting MISO's resource adequacy requirements?

A28. The 2023/2024 MISO Plan Year was the first year that MISO used a seasonal construct, as opposed to yearly, in establishing resource adequacy requirements. This change is discussed further in Part V. MISO's resource adequacy construct has four seasons; Summer (June, July and August), Fall (September, October, November), Winter (December, January, February) and Spring (March, April, May). DTE Electric registered 831 MWs (installed capacity or ICAP) of demand response for the summer season, equating to 912 Zonal Resource Credits (ZRCs).

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The seasonal breakdown of ICAP MWs and ZRCs used to meet resource adequacy requirements in Planning Year 2023/24 is in Table 2.

Table 2 2023/24 ICAP MWs (ZRCs) by Season

Summer	Fall	Winter	Spring
831 (912)	368 (431)	363 (465)	318 (403)

Q29. How does the Company's DR portfolio compare to other utility DR portfolios?

A29. In 2022, the U.S. Energy Information Administration (EIA) ranked DTE Electric's DR portfolio the fifth largest in the country in terms of Potential Peak Demand Savings. EIA also ranked the Company's portfolio as the largest in MISO in terms of Potential Peak Demand Savings.

Q30. What is the intent of the DR pilot offerings?

A30. Pilots are potential programs focused on understanding technology or design and determining whether they can become full-scale programs that will deliver accountable peak demand reductions or shifts in energy consumption. The Company will determine which pilots may become programs in the DR portfolio on a case-by-case basis.

Q31. Why is it important to continue to invest in DR pilots?

A31. Continued investment in DR pilots allows the Company to stay at the forefront of new or emerging DR technologies and evaluate whether the technologies or program design will provide benefits to the Company and its customers. Investment in DR pilots also can shape future designs of programs and provide valuable learnings as the DR landscape changes.

Q32. What DR pilots is the Company developing or conducting to continue to diversify the portfolio as well as offer more options for potential DR customers?

A32. The Company is conducting pilots that include an electric vehicle (EV) DR pilot (Smart Charge), a residential home generator pilot, and a C&I Battery storage pilot. The Company is also developing a Vehicle-to-Home (V2H) pilot. These pilots will be discussed in detail later in my testimony.

Q33. What is the overall purpose of continued investment in DR?

A33. DR programs are, and will continue to be, an important part of DTE Electric's integrated resource portfolio and are part of a utility system framework within the comprehensive context of an IRP process. The Company has been managing and investing in a diverse range of programs and pilots that serve as resources in the Company's IRP.

Changes have been occurring in the energy landscape including energy legislation, regulatory framework, and environmental regulations. These changes, coupled with a shift from fossil fuel-based generation to cleaner energy resources, are driving investment in a DR portfolio to help meet the Midcontinent Independent System Operator's (MISO) resource adequacy requirements. A portfolio of pilots and programs enables the Company to continue providing secure, reliable, and sustainable energy supply to its customers under a changing generation capacity and energy landscape.

Part IV: DR Portfolio Investment

Projected Capital

Q34. How much capital is the Company forecasting to invest in the DR portfolio during the bridge year, January 1, 2023, through December 31, 2024, and the forecasted test year, January 1, 2025, through December 31, 2025?

A34. As shown in Exhibit A-12 B5.6 p1, during the bridge period the Company is forecasting to invest $2.2 million on the CoolCurrents Program, $8.3 million on the SmartCurrents program, and $6.9 million on other DR programs and pilots. In addition, during the forecasted test year the Company is forecasting to spend $0.5 million on CoolCurrents, $2.5 million on SmartCurrents and $1.4 million on other DR programs and pilots. In total, the Company is forecasting DR capital investments of $17.4 million during the bridge period and $4.4 million during the forecasted test year.

Q35. What is the status of the Company's CoolCurrents LCD replacement program?

A35. As of December 31, 2023, approximately 260,000 residential customers and over 800 commercial customers take service on the D1.1 rate. The Company began replacing outdated legacy Radio Control Units (RCUs) in 2015 after identifying that the legacy RCUs were in need of repair, prone to malfunctioning, and difficult to service as some units were installed as early as the 1980's. Since then, the Company has successfully replaced an estimated 170,000 legacy RCUs with a two-way communicating 24v LCD. The replacement LCD provides the Company with increased flexibility to interrupt based on geographic area or other subgroups as well as determine whether devices are online and available for interruption or offline.

Throughout 2023, the Company focused on continuing to replace RCU devices as well as investigating previously installed LCDs that are offline. Nearly 25,000 previously installed replacement LCDs (out of 170,000) are no longer joined to the electric meter and thus not available for interruption. Based on the field investigations conducted in 2022 and 2023, around 70% of the replacement LCDs investigated are due to the customer wiring no longer supplying the required 24v. Other reasons for offline devices are unrecorded meter changes or a device reset required due to a meter firmware upgrade. Making better use of data analysis and procedures for upgrading meters, DTE Electric is working to reduce the need for field investigations of offline devices.

Q36. Could you explain the status of the remaining CoolCurrent customers?

A36. Yes. Approximately 90,000 CoolCurrent customers still have legacy RCUs primarily due to not having the proper wiring in place to power a replacement LCD. Without the proper wiring available to provide power to the 24v LCD, the LCD will not be installed. To address this issue the Company is evaluating the installation of an alternative new LCD.

Q37. How does installing an alternative new LCD provide a solution to customers that do not have the proper wiring needed to support a replacement LCD?

A37. The replacement LCD, like the older RCUs, relies on a 24v line that is run from the customer's furnace for power. The Company has found that when a customer services or replaces their heating, ventilation, and air conditioning (HVAC) unit, this line is often not reattached or is simply removed. To replace or repair the 24v line, it is estimated that a customer would have to pay a contractor, on average, between $80 to $200 to make the replacement LCD functional. This is also comparable to what a customer with a legacy RCU would spend to ensure the proper wiring is in place for a replacement LCD.

The alternative 240v LCD connects directly to the customer's HVAC unit and pulls its power from the unit making the 24v line no longer necessary. By offering this alternative LCD, CoolCurrents customers can remain enrolled in the program without any additional cost, as the device is not dependent on a dedicated, customer supplied separate 24v line.

Q38. Has the Company worked with any other utilities to gather learnings about the alternative 240v LCD?

A38. Yes. The Company had discussions with Consumers Energy (CMS), who use a similar 240v LCD, to better understand how the alternative LCD is installed and operates. This included an installation go and see by the Company's field personnel with CMS field installers. The go and see allowed the Company's field personnel to see the alternative LCD installation process as well as learn what type of equipment and components are needed and to ask questions directly to experienced installers. In addition, the CoolCurrents Program Manager discussed the alternative LCD with the CMS Program Manager to gather further learnings from their experiences. After the collaborative field events conducted with CMS installers, DTE Electric field service personnel determined that similar devices could be installed by the Company's personnel. DTE Electric field service trainers are currently developing a training course which all field service representatives are anticipated to complete in the second quarter of 2024.

Q39. Has the Company ordered any alternative LCDs that do not require a 24v line?

A39. Yes. In 2023, the Company ordered and accepted delivery of nearly 5,000 alternative LCDs that are targeted to be installed in 2024. In addition, the Company has ordered the various components that are necessary for the installations. The installation of the alternative LCD devices will be used to gauge whether this is a viable solution for customers who do not have the proper 24v wiring. Assuming that there is a willingness on the part of customers to have the alternative 240v LCD installed on their appliance, and DTE Electric field service executes requested installations as anticipated; this device will likely provide a satisfactory alternative to the 24v device.

Q40. How is the Company selecting which CoolCurrents customers may receive the alternative LCD?

A40. These alternative devices will initially be offered to customers that are currently enrolled in the CoolCurrents program, allowing them to remain in the program without the need to hire a contractor to repair their 24v line. As per the D1.1 rate, CoolCurrents customers have a separate meter to record AC or heat pump consumption. In January 2024, the Company initially targeted approximately 200 customers, located on the Fisher substation, who were contacted in 2022 to repair the 24v wiring and do not currently have the 24v connection required to support the replacement LCD. This initial 200 customer targeted effort supports the Non-Wires Alternative (NWA) pilot in collaboration with DTE Electric's Distribution Operations team. Beginning in March 2024, the Company will contact approximately 4,000 customers, and more if needed, in two batches of around 2,000 customers, who do not have a 24v connection.

Q41. How will the Company determine if the alternative LCD provides a solution to customers that are offline and/or without the proper voltage?

A41. To determine if the alternative LCD is a viable solution the Company will consider customer acceptance, ease of installation, and functionality of the alternative LCD.

Q42. What actions will the Company take if a CoolCurrents customer refuses the alternative LCD and does not have the proper wiring?

A42. If a customer continues to be non-compliant even after being offered an alternative LCD, they will be removed from the tariff and other DR programs, such as Smart Savers or SmartCurrents, will be marketed as alternative DR programs to maintain their support of DR programs.

Q43. Could you describe the capital investment of $2.2 million in the CoolCurrents program during the bridge year and of $0.5 million in the forecasted test year?

A43. The capital investment through 2025 will be used to order and install alternative LCDs to address customers who do not have the proper wiring in place. In addition, the investment will support continued investigations into offline devices, install new or replacement LCDs and program operation costs. The capital investment for the CoolCurrents Program can be seen on Line 1 of Exhibit A-12, Schedule B5.6.

Q44. Why is the Company continuing to make these improvements?

A44. The Company identified that replacing the outdated infrastructure results in a higher capacity value through increased capabilities and effectiveness. The LCDs are two way communicating devices providing the Company the capability to determine whether devices are available for interruption. They also provide flexibility to interrupt at substation or circuit level. With continued investment in the CoolCurrents program, DTE Electric can extend the equipment life and continue to provide an additional DR program option for residential and commercial customers. In addition, the CoolCurrents program is a direct load control DR program that doesn't allow for customer opt outs adding additional value to the Company's DR portfolio and further supports resource adequacy.

Q45. What changes has the Company made to the SmartCurrents program?

A45. In August of 2023, SmartCurrents was relaunched with changes to the program. One of the changes included the separation of the program from the DPP rate. Other changes included upgrading the thermostat to an ecobee Premium Thermostat, providing an annual participation incentive to increase retention, and revising the DR event parameters to increase the flexibility and availability of SmartCurrents as a MISO LMR resource. While the program was being redesigned to incorporate these changes, program recruitment was paused.

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Q46. Why did the Company think separating the SmartCurrents program from the DPP rate was necessary?

A46. Separating the SmartCurrents program from the DPP rate responds to feedback heard directly from customers in an ad hoc quantitative survey to understand how they would rate select attributes of the SmartCurrents program. In addition, this change allows customers to select the rate that best fits their household and lifestyle. Removing the tariff requirement also opened eligibility to customers who previously may have been denied enrollment due to tariff incompatibilities. In addition, this change allowed the Company to make the necessary changes to the event parameters to better align with the Company's other DR programs.

Q47. Have the program changes had an impact on customer enrollment since the relaunch in August of 2023?

A47. Yes. Since relaunch, the program has enrolled a net 7,820 customers as of December 31, 2023, which is 29% of all program enrollees currently active as of the same date.

Q48. Could you describe the $8.3 million bridge year capital investment and $2.5 million test year capital investment into the SmartCurrents Program?

A48. The Company is projecting to grow the cumulative number of enrolled thermostats from approximately 27,000 as of December 31, 2023, to 35,000 enrolled thermostats at the end of 2024 and 40,000 at the end of 2025. Towards the end of 2022 and through the first half of 2023, the Company redesigned the SmartCurrents program. As noted above, the redesign included the removal of the DPP rate requirement, as well as adjusting the callable event hours and adding an annual

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incentive to the program. The multitude of changes in the redesign required updates to program management, IT processes, data transfers, marketing materials, and installation training, thus contributing to the increased costs over the bridge period. The Company also chose to update the thermostat offering to a newer model, the ecobee Smart Thermostat Premium. The new ecobee Smart Thermostat Premium comes with a smart sensor and offers additional functionality such as indoor air quality monitoring and can deliver personalized energy recommendations.

In 2024, the Company is projecting to spend approximately $4.0 million primarily on contractor costs and materials. Beginning in 2025, the Company is forecasting to spend $2.5 million to support the SmartCurrents Program. The continued investment in the SmartCurrents program will ensure the continued success of the program, support the Company's program enrollment goals and increase the MW capacity. The capital investment in the SmartCurrents Program can be seen on Line 2 of Exhibit A-12, Schedule B5.6.

Q49. Can you provide a further breakdown of the SmartCurrents capital costs?

A49. Capital costs associated with the SmartCurrents Program consist of primarily of contract labor and materials. Contract labor is provided by ICF and EnergyHub, and materials consists of the ecobee device costs and associated API license. In addition, there is internal DTE Electric labor to support the program, that includes program management, internal IT labor and digital assistance. ICF assists in the management of the SmartCurrents program in many facets including, but not limited to, thermostat scheduling, installation and reporting, program management, recordkeeping, IT support, customer communication and marketing development,

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as well as coordinating thermostat purchases. ICF supported the program redesign. EnergyHub is the third-party integrator and their platform that is used communicate with the enrolled thermostats which includes determining if the thermostat is online and dispatching event notifications to host thermostats and making the temperature offset when a DR event is called.

Q50. What changes has the Company made to the SmartCurrents program in an effort to reduce program costs?

A50. Some of the changes made to reduce program costs include:

- When a customer selects professional installation at the time of enrollment, rather than shipping the thermostat to the customer, the installer brings the thermostat to the customer's residence during the installation appointment. This eliminates the shipping costs and materials for customers selecting professional install at the time of enrollment. Since relaunch through the end of 2023, approximately 54% of customers elected professional installation.
- The Company added virtual installation as a new installment option which saves, on average, $80 compared to an in-person professional installation appointment. This provides a virtual agent to help walk through thermostat installation with the customer, ensuring proper connection and not requiring or reducing an in-person installation. Since relaunch, 7% of customers opt for virtual installation at the time of enrollment as of year-end 2023.
- A new installation scheduler tool is offered that provides customers with the ability to schedule their own installation appointment, rather than having to contact the call center to do so. This tool also has a chat function that provides customers with

troubleshooting support, reducing the need for service calls. As of December 31, 2023, customers have scheduled 40% of their own appointments since the relaunch.

- When a customer returns a thermostat, they are provided a return label via email versus being mailed a return label, reducing postage costs.

Q51. Has the Commission been supportive of the SmartCurrents Program in previous filings?

A51. Overall, yes. While MPSC Staff generally supports the program, it was agreed upon in the 2021 DR Reconciliation settlement, Case No. U-21242, to disallow $1,672,895 in capital expenses associated with the SmartCurrents Program. The MPSC Staff recommended the disallowance citing that the program was only preapproved for $3 million in 2021 through Case No. U-20471 (the Company's 2019 IRP). The disallowance (~$1.7 million) is the difference between the actual spend on SmartCurrents in 2021 and $3.3 million ($3 million plus 10%).

Q52. What reasons did Staff cite in recommending the disallowance?

A52. The Staff did not find the overspend to be reasonable because of the lack of value of these costs demonstrated by the Utility Cost Test. The SmartCurrents spend over the authorized amount was primarily attributed to creating a new webpage to redesign, enhance, and streamline the potential and existing participant customer journey. Specifically, the webpage and platform allowed for self-service enrollment, unenrollment and management of DPP event communication preferences. At the time of the 2021 DR reconciliation filing, the Company could not correlate increased enrollments and event participation to the development of the new webpage.

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Q53. Is the Company requesting recovery for the $1,672,895 that was originally disallowed in the 2021 DR reconciliation?

A53. Yes. Although the Company properly eliminated the disallowed capital from the balance sheet Exhibit A-2, Schedule B6.1, the Company believes there are benefits from these costs and that it should be allowed to recover them. If the Commission approves the Company's request for recovery, $914,448[1] should be added to the projected test year rate base.

Q54. Does the Company have any updated metrics that can be directly attributed to the 2021 spend on the platform and webpage development for the SmartCurrents program?

A54. Yes. The Company did recognize an increase in conversion rate from 14% to 46% and the average time to process enrollments decreased from an average of seven days to one day. Looking back, the number of customers who enrolled in SmartCurrents from August 21, 2020, through August 20, 2021, was 6,736. After the webpage went live in 2021, 10,120 customers enrolled within the same timeframe over the next year, resulting in a 50% increase in enrollments. Since the program's 2023 relaunch, 98% of customers have enrolled through the self-service channel that was set up in 2021. This supports the investments the Company made in 2021 to the SmartCurrents program, specifically to the platform and the webpage development, provided value to the program and the $1,672,895 of disallowed capital should be considered reasonable and prudent and therefore recoverable.

[1] The amount is based on a January 1, 2025, balance of $1,081,737 and December 31, 2025, balance of $747,158; $334,579 should be added to depreciation expense.

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Q55. How much capital is the Company forecasting to invest in Other Demand Response Programs and Pilots?

A55. As can be seen on Exhibit A-12, B5.6, the Company is forecasting to spend $6.9 million in capital during the 24-month bridge period ending December 31, 2024, and $1.4 million during the forecasted test year ending December 31, 2025, in Other Demand Response Programs and Pilots.

Q56. What capital investments are included in Other Demand Response Programs and Pilots?

A56. The Other DR Programs and Pilot category on Exhibit A-12, Schedule 5.6, line 3 includes both pre-approved programs from DTE Electric's most recent IRP settlement, Case No. U-21193, and existing on-going pilots. In the Company's settlement of Case No. U-21193, the capital associated with C&I Dashboard and Interruptible Water Heating replacement programs were pre-approved and are included in this capital investment amount. The current pilot that the Company is evaluating that has associated capital spend beyond what was included in the IRP for pre-approval is the C&I Battery Pilot.

Q57. What is the C&I Dashboard that was pre-approved in Case No. U-21193?

A57. The Company issued a Request for Proposal in 2023 and is successfully partnering with Enel X North America, Inc. as a result to provide certain C&I interruptible customers, likely customers taking service under D8, R10 or R12, with technology to help improve their DR performance during called events. These tariffs represent 439 MW (80% of the MWs available during the MISO 2023/24 summer season) so their performance is critical to reliability. The technology provides customers with near real-time telemetry meter data so that a DR event can be monitored prior to, during, and after it occurs. The data is displayed on a dashboard that is accessible by both the customer and the Company. Providing customers with near real-time telemetry will better equip them to curtail load during DR events in accordance with their contracted load reduction value. The technology also provides the Company analytics for better DR forecasting and post-event analysis. Initially, the Company plans to provide the dashboard to interested customers for up to 55 customers' sites, and add up to 10 new sites in 2025, although it is anticipated that the number of sites may increase as the Company gains hands-on experience with the dashboard. It is anticipated that the first customers will have the necessary equipment installed and access to the dashboard in the first half of 2024.

Q58. How much capital does the Company anticipate spending on the C&I Dashboard over the bridge period ending December 31, 2024, and the forecasted test period ending December 31, 2025.

A58. The Company anticipates spending $1.0 million during the bridge period to support the setup of the customer sites and provide access to the dashboard and $350,000 during the forecasted test period to continue access to the dashboard for current customers and add additional customer sites.

Q59. Could you describe the capital investment in the Interruptible Water Heating program?

A59. Yes. Similar to the CoolCurrents Program, the Company's LCDs that operate the Interruptible Water Heating program and reside in customers' homes are no longer functioning as intended and are due for an upgrade. The Company plans to begin

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replacing water heating LCDs for customers taking service on D5 (approximately 45,000) in 2024. The Company purchased 864 new water heating LCDs in 2023 with plans to purchase an additional 864 LCDs in 2024, equating to a total of 1,728 new units. The Company will leverage the learnings from the CoolCurrents LCD replacement program including notifying customers of the work that will be performed, educating customers on the rate discount as well as preemptively reaffirming customers desire to remain in the program prior to sending a field service installer to perform the work. If a customer does not wish to remain in the Interruptible Water Heating program, they will be removed from the rate and a new LCD device will not be installed in their home. After the initial targeted replacements are performed in 2024, the results will be evaluated with the expectation that installations will increase in subsequent years.

Q60. Is 24v wiring required, similar to the Company's CoolCurrents replacement LCDs?

A60. No. There is no need for a separate 24v power supply with interruptible water heating services. The control unit is wired directly to the power source in the dedicated meter enclosure and therefore does not need a separate power source.

Q61. How much is the Company forecasting to spend on this program during the bridge period ending December 31, 2024, and during the forecasted test period ending December 31, 2025?

A61. The forecasted capital investment associated with the Interruptible Water Heating program is included in the Other Demand Response Programs and Pilots category on Line 3 of Exhibit A-12, Schedule B5.6. The Company is forecasting to spend

$345,197 in capital during the bridge period and $500,000 in capital to support customer LCD installations during the forecasted test period, which is less than the $1,000,000 that was pre-approved in the IRP settlement as the Company ramps up the replacement LCD installations.

Q62. What is the C&I Battery Storage pilot?

A62. The C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate battery energy storage system (BESS) that will be located at two customers' sites. It is designed to test the ability to achieve peak demand shaving or shifting during DR events. The Company is targeting a two-year pilot period following installation and commissioning of the batteries. Refer to Exhibit A-12, B5.6.1 for additional detail on this pilot.

Q63. Can you discuss the main objectives of the C&I Battery Storage pilot?

A63. Yes. The main objectives of the pilot are as follows:

- Engage with customers to better understand their interest in hosting and potentially operating a BESS;
- Gain operational experience on battery installation, management, and control interfaces when the system is located at a customer's site as opposed to a Company site;
- Assess feasibility for sharing asset control between customer and the Company; and
- Evaluate the effectiveness of the BESS to achieve system peak demand reduction when a demand response event is called by the Company;

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- Assess customer's actions to achieve demand charge and overall bill reductions;
- Facilitate the understanding of multiple energy storage values, compensation models, and the integration of battery storage in wholesale markets to support tariff development as contemplated by the Commission's Order in MPSC Case No. U-21032.

Q64. Could you describe the status and progress of the C&I battery pilot?

A64. Both batteries have been ordered, shipped from China, and have arrived in the US. The switchgear component, which has an approximate 38-week lead-time, was approved in December 2023, and both switchgears were ordered on December 27, 2023. Hitachi will be working on the detailed design portion of the project in the first quarter of 2024.

As part of the implementation plan, the Company has identified one customer. The Company intends to leverage the commercial agreement developed and agreed upon by the first participant as a template for the agreement between the second participant. Due to lead time of major equipment, installation at the first customer's site has taken longer than anticipated, although is targeted for Q2 2025. The Company is confident that a second participant will be identified in partnership with Company's MAS group in the first half of 2024 and that the second battery will be installed shortly after the first. Once the second customer has been identified and the first installation is underway, the installation of the second battery will begin. The Company plans for both batteries to be operational by the end of 2025. The initial proposed event schedule includes no more than 30 planned DR events per year and five emergency DR events, with a least one-hour customer notice, per year. However, per the order in Case No. U-21297, the Company will meet with the MPSC Staff to discuss an appropriate number of required test events each year.

Q65. Did the Commission approve all capital costs related to the C&I battery pilot in Case No. U-21297?

A65. No. In Case No. U-21297, the Commission excluded approximately $2.0 million ($1,990,360) of the capital spend on the C&I battery pilot because the Company did not intend on signing up a second customer until the first battery was installed and did not provide a timeline; thus, Staff did not believe that half the capital would be used and useful in the projected test year. In 2022, the Company spent $2.5 million in capital to procure the equipment for the C&I battery pilot which was partially recovered in Case No. U-21403 2022 DR Reconciliation. The exclusion included $1.25 million related to half of the procured equipment which was spent during the bridge period (2022) and $0.75 million in forecasted test year (2023) spend.

Q66. Does the Company believe that Staff's concern remains in this instant case?

A66. No. As stated above, the Company expects to have a second customer secured in the first half of 2024 with both batteries operational by the end of 2025, and as such is requesting the previously excluded costs as mentioned above.

Q67. How much capital does the Company anticipate spending on the C&I Battery pilot over the bridge period ending December 31, 2024, and the forecasted test period ending December 31, 2025.

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A67. The Company anticipates spending $1.4 million during the bridge period to procure and install equipment and $0.6 million in the forecasted test year to primarily support final installation costs. Capital spend was moved from 2023 to 2024 and 2025 due to lead time of major equipment critical for progression of both batteries.

Projected O&M

Q68. How much O&M is the Company forecasting to spend in 2025 on DR?

A68. The Company is forecasting to spend $5.9 million in 2025 to support the development and execution of its Demand Response Portfolio. This represents a $3.2 million increase from 2022 levels (a $0.2 million increase to account for inflation and $3 million for specific adjustments). This can be seen on Line 9 of Witness Bennett's Exhibit, A-13, Schedule C5.9.

Q69. How much O&M is needed to support the Company's Smart Savers Program going forward?

A69. The Company is projecting to grow the cumulative number of enrolled thermostats from nearly 64,000 as of December 31, 2023, to more than 90,000 enrolled thermostats by the end of 2025. In 2024, the Company is projecting to spend approximately $2.5 million on anniversary device fees for devices that were enrolled prior to 2024. In 2024, the Company is forecasting to enroll 12,000 new devices which result in additional devices fees. Beginning in 2025, the Company is forecasting to spend $3.3 million to support the Smart Savers Program. The requested O&M spend is necessary to support the continued successful growth of the program the Company has experienced since its inception including the annual

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portal fee and annual device fees, with annual devices fees increasing each year based on the projected increase in enrollments.

Q70. How much O&M is the Company forecasting to spend in Pilots and Other Projects?

A70. The Company is forecasting to spend $2.6 million in O&M to support various DR pilots, programs and projects. The pilots in this spend include the Smart Charge, V2H, Residential Generator and the Non-Wires Alternative (NWA) efforts. Programs such as the Company's CoolCurrents and SmartCurrents and the replacement of the LCDs for the Interruptible Water Heating customers will also be supported by O&M Spend. O&M spend for these programs and pilots supports labor, marketing and communication efforts as well as portal, dispatch, program incentive and platform fees. Other DR projects are included in this category as well. The $2.615 million in O&M is broken out by the various projects in Table 3.

Table 3 2025 Forecasted Spend

Pilot/Program/Project	Forecasted Spend
SmartCurrents	$105,000
CoolCurrents	$136,000
Smart Charge	$767,000
Interruptible Water Heating	$62,000
Residential Generator	$161,000
Vehicle to Home	$96,000
Non-Wires Alternative	$18,000
Other Projects	$1,270,000
Total	$2,615,000

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Q71. Could you describe the electric vehicle (EV) DR or Smart Charge pilot?

A71. The initial design of Smart Charge, which launched in 2019, was to assess the effectiveness of Open Vehicle Grid Integrated Platform (OVGIP) concept to integrate EV charging with grid objectives through demand response. This initial design ran until May of 2023.

After completion of the initial design, the Company, modified the focus of the pilot to incorporate managed charging, starting in July 2023. One of the main reasons the Company transitioned to managed charging was due to the mandatory roll out of residential electric time of use (TOU) rates in March 2023. In this phase of the pilot, the Company's managed charging approach ties each participant's enrollment to their specific TOU rate schedule and automatically initiates charging to occur during their off-peak rate period when it's the lowest cost for them and most beneficial to the system. In addition, the Company is interested to learn if there's an impact of the Company scheduling participant's daily charging automatically through vehicle telematics and managed charging participation for them, or if EV users are already scheduling their charging during off-peak time periods without the Company's assistance. Refer to Exhibit A-12 B5.6.4.

Throughout 2023, the Company continued its partnership with Ford, General Motors (GM), and BMW through the OVGIP while adding a new partnership with WeaveGrid. WeaveGrid is a platform that connects utilities, original equipment manufacturers (OEMs), and EV drivers and is the platform that is used to enroll eligible Tesla drivers into the Smart Charge pilot. The pilot will continue through the end of 2024.

While the OVGIP is funded through the DR O&M budget, the partnership with WeaveGrid was made available through the Emerging Technology Fund (ETF) that was approved in Case No. U-20836[2]. The OVGIP forecasted spend will be subject to future DR reconciliation while the spend associated with WeaveGrid will not be subject to future DR reconciliations.

Q72. Could you describe the status and progress of the Smart Charge pilot?

A72. Yes. In 2019, the Company worked with Electric Power Research Institute (EPRI), Sumitomo, Ford, and GM. The first phase of the pilot concluded after six months in August 2019 after calling 12 events with approximately 165 Ford and GM employee EV drivers. The second phase of the pilot expanded beyond automotive employees to any Ford and GM drivers in the Company's service territory, increasing to 370 participants. DTE Electric dispatched DR events for the eight months ending December 2021, resulting in 1.7 MWh of avoided energy consumption during called events.

In May 2022, BMW joined the next phase with Ford and GM, which grew to 663 participants and called 44 DR events over the 12-month period ending May 2023. The Company and OEMs identified an aggregate avoided energy total of 14 MWh across all 44 events. The DR events were all two hours in length and were called during different days of the week (weekdays only) and different times of the day to

[2] As described in Q/A 111 of Burns' Testimony (Case No. U-20836)

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test customer participation levels and to understand how much avoided energy the Company could expect to achieve based on the number of participants enrolled. The Company observed the best avoided energy results during the 12am-2am time periods, since most EV owners typically charge their EV overnight, presumably due to more prevalent daytime work hours and cheaper off-peak rates. The average aggregated avoided energy per enrolled EV during the 12am-2am event window was 1.33 kWh. The average aggregated avoided energy per participating EV during the 12am-2am event window was 9.04 kWh.

Beginning in July 2023, after the conclusion for the 2022/23 pilot year, the Company and OEMs had to re-recruit customers. The expansion of the pilot to support managed charging required a change in terms and conditions by the OEMs. As of December 31, 2023, there were 1,224 EVs enrolled in the Smart Charge pilot. GM, Ford, and Tesla began enrolling customers in 2023, while BMW began enrolling customers in Q1 of 2024. The Company will continue to recruit customers for this pilot through 2024. Once a participant enrolls, Smart Charge automatically schedules daily charging to meet their charging needs during their off-peak rate times. This scheduled charging occurs on the weekdays only. The Company also plans to call up to five DR events, June through September, to evaluate how much demand and energy savings can be achieved.

Q73. Is the Company planning to make Smart Charge a program within the DR portfolio?

A73. Yes. The Company believes that the Smart Charge pilot should become part of the Company's DR portfolio beginning in 2025. With continued allocated O&M

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resources, along with the forecasted increased adoption of EVs, Smart Charge is expected to continue expanding. Transitioning Smart Charge to a program also allows for more customers to participate in the program above the current pilot customer cap of 2,000. In addition, with this commitment, the Company will remain at the forefront of developing technologies and continue to collaborate with important OEMs within the service territory as EV adoption continues to grow.

Q74. How much is the Company forecasting to invest in O&M in the Smart Charge Program?

A74. The Company is forecasting to spend $0.8 million to support the expansion of the Smart Charge Program. The investment in Smart Charge will allow the Company to transition to a program and support increased participant enrollment. The costs are associated with platform fees, marketing and customer participation incentives.

Q75. Has the Commission and MPSC Staff been supportive of the Company's efforts in pursuing a Smart Charge?

A75. Yes. The MPSC Staff and Commission have supported the Smart Charge pilot in several cases including the 2019 IRP (Cast No. U-20471), 2022 Electric Rate Case (Case No. U-20836), 2023 Electric Rate Case (Case No. U-21297), as well the DR Reconciliation Cases beginning with Case No. U-20521 filed in 2019.

Q76. Could you describe the vehicle-to-home (V2H) EV pilot?

A76. The Company is partnering with two leading OEMs to evaluate V2H technology. This pilot, as detailed in Exhibit A-12, B5.6.3, is one of the first in the country and expands the DR team's EV portfolio and collaboration with leading OEMs. The

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Company finalized a preliminary agreement in December 2023 and is targeting a completed Statement of Work in the first half of 2024 that will be used as the basis for this pilot. Similar to the WeaveGrid portion of Smart Charge, the funding for the software components and the monthly EV fees of the participating OEMs was made available through the Emerging Technology ETF that was approved in Case No. U-20836[3]. The O&M requested in this instant case will support the incentives associated with customer enrollment and participation and will be funded by Demand Response. The forecasted incentive spend will be subject to future DR reconciliation while the spend associated with software and monthly fees will not be subject to future DR reconciliations.

Initially, the pilot is scheduled to run for 12 months after the completion of the SOW. In this pilot, the Company and OEMs will manage the discharge of energy from eligible EVs that are owned or leased by eligible participants. Participants must be DTE Electric residential customers, with a bi-directional charging station already installed at their home to allow the Company to dispatch events and evaluate the feasibility, cost, and customer interest and behavior. Some of the benefits of a V2H type of pilot include:

- Providing backup power to a home in the event of an outage or periods of high strain on the electric grid;
- Reducing customers' electric bills by signaling the EV to use its battery power during on-peak demand times when electricity from the grid is most costly.

[3] As described in Q/A 111 of Burns' Testimony (Case No. U-20836)

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Q77. Can you describe the objectives of the V2H pilot?

A77. Yes. The Company is initially targeting up to 400 eligible participants in its first pilot year to ensure any issues (i.e., communication or signal issues) are resolved prior to the potential expansion to the Company's broader electric customers with eligible EV models. The Company plans to evaluate the success of the pilot as it relates to:

- Targeting and recruitment efforts needed to enroll in this type of pilot;
- Determining the appropriate time and length to dispatch events based on the most optimal time to charge and discharge the EV for the participant and the Company;
- Understanding what incentive structure prompts customer participation;
- Determining how much demand (kW) and energy (kWh) savings the Company could expect to achieve with the pilot's current participants as well as future potential as additional eligible EV models are available in DTE Electric's service territory;
- Assessing customer receptiveness and the value to the participants and the Company for this type of V2H pilot;
- Identifying and processing new learnings that could be applied to current and future DR V2H offerings; and
- Assess the viability of this resource acting as a year-round DR asset responding on short-term notice for peak events.

Q78. Can you describe the residential home generator pilot?

A78. Yes. The Company is conducting a residential customer-owned natural gas generator pilot. The pilot leverages Generac Grid Services' platform and utilizes

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telemetry to shift customers' electric load to the customers' generator in real-time during Company called DR events. Customers were prescreened for eligibility to participate in the pilot and were targeted accordingly. One qualifier to participate was, "owner has a premium or dealer managed subscription to Mobile Link." The premium or dealer managed Mobile Link subscription allows the Company to operate a switch-free program capable of remote operations such as responding to demand response events. Through benchmarking with CMS, the Company learned switch programs are more expensive due to the cost of physical LCDs and the associated truck roll for the installation of the LCD. Customers have the options to opt-out of up to two events per calendar year, throughout the duration of the program. Events can occur on any non-holiday weekday between the hours of 8:00 am and 8:00 pm within any MISO season, can last no more than four hours and are limited to 40 hours in total each calendar year. The pilot will conclude in December 2025. Refer to Exhibit A-12, B5.6.2 for details.

Q79. Can you describe the main objectives in pursuing a residential home generator pilot?

A79. Yes. The main objectives of the residential generator pilot are as follows:

- Determine whether customers would be willing to actively participate and allow for real-time telemetry to control their generators during an event;
- Assess the viability of a pilot that can act as a year-round DR asset responding on short-term notice for peak events;
- Assess customer receptiveness and the value customers receive from a residential generator pilot; and

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- Identify and process new learnings that could be applied to current and future demand response offerings.

Q80. Is the Commission and MPSC Staff supportive of the Company's efforts in pursuing a residential home generator pilot?

A80. Yes. However, when the pilot was first introduced in Case No. U-20836, it was argued by the MPSC Staff that the Commission should disallow the O&M spending associated with the residential generator pilot as there was a concern that the pilot was not well developed. The Commission ultimately agreed with the MPSC Staff. Since that order, the pilot has been further developed. The Company took the recommendation from Staff to benchmark with CMS on their residential generator pilot and leverage their learnings and experience. In the Company's latest general rate case, Case No. U-21297, both MPSC Staff and Commission supported the O&M spend associated with the residential generator pilot, citing the progress the Company has made in the pilot development.

Q81. Could you describe the status of the residential home generator pilot?

A81. Yes. In 2023 the Company launched a 200-participant cap residential customer-owned natural gas generator pilot, Demand Response Home Generator Program, in partnership with Generac Grid Services. Recruitment efforts began in July 2023 and continued through September 2023, resulting in successful enrollment of 197 customers. The Company called its first pilot event on November 28th, 2023.

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In 2024 the Company is considering a second phase of recruitment to target up to 200 additional participants. This second phase of recruitment would provide the opportunity to offer the pilot to a larger subset of different customers.

Q82. Are there Other DR Projects that are included in the Pilots and Other Projects Category?

A82. Yes. Other DR projects include initiatives that may not necessarily be tied to a specific program or a pilot. The Company plans to set up a dedicated DR call and is exploring partnering with an external party to do so. With a dedicated call center, representatives will be specially trained to inform customers of DR program offerings and benefits and answer customer inquiries on DR programs improving their experience. In addition, the Company is considering partnering with a third-party evaluator to measure the performance of its DR portfolio. This partnership will look at the portfolio holistically and potentially identify improvements to its DR programs. The Pilots and Other Projects category also includes necessary costs to support the competitive DR procurement process that was agreed to in the IRP settlement in Case No. U-21193.

Q83. Can you explain the competitive DR procurement that was part of the settlement of Case No. U-21193?

A83. Yes. In the settlement of the Company's 2022 IRP, DTE Electric agreed to procure DR-related MISO Zonal Resource Credits (ZRCs) through a competitive bidding process. Specifically, the Company agreed to issue two 25 MW solicitations, one for the 2025/26 Planning Year (PY) and one for the 2026/2027 PY as well as a 100 MW solicitation for the 2027/28 PY. The Company plans to spend O&M to contract

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with a third-party to assist the Company with developing and supporting the procurement process. The O&M to support this DR procurement effort is expected to be spent in 2024 through 2027.

Q84. Can you summarize the Capital and O&M investment amounts for the Company's DR Portfolio?

A84. Yes. The Company is forecasting to invest $17.4 million in capital during the bridge period beginning January 1, 2023, and ending December 31, 2024, and investing $4.4 million in capital during the forecasted test period ending December 31, 2025. In addition, the Company forecasts O&M spend of $5.9 million. This overall level of investment will support the Company's current program offerings such as CoolCurrents, Smart Savers, SmartCurrents, and Smart Charge as well as allow the Company to conduct and evaluate pilots to determine if they can become a valuable resource within the portfolio. This spend also supports other DR related projects.

<u>Forecasted MWs</u>

Q85. What are the forecasted MWs in the DR portfolio as a result of continued investment in the programs and pilots?

A85. The Company is forecasting a decrease in the portfolio from 786 MWs in 2022 to 712 MWs in the 2025/2026 PY as shown in Table 4. The primary drivers of the projected decrease are the CoolCurrents program and the C&I tariffs. The Company has reduced the MWs associated with the CoolCurrents program to more appropriately reflect the customers who can be successfully interrupted. In addition, the MWs associated with the C&I tariffs was reduced to reflect current customers and their associated operations. This decrease is offset by additional MWs associated with the Smart Savers program primarily due to increased participants in the program. The Company also recognizes that as MISO continues to explore short-term and long-term accreditation changes there will likely be impacts to the amount of MWs available in the Company's DR Portfolio. The Company is committed to continued growth of the portfolio and prudent spending to assure the Company and its customers are receiving the maximum benefits of demand response. However, the Company will need to remain flexible and understands that the changing customer preferences and evolving DR landscape can change the MW makeup of the portfolio.

Table 4 Projected 2025/2026 PY MWs (ICAP)

Program	Projected 2025 MWs
Smart Savers	108
SmartCurrents	48
CoolCurrents	130
Legacy Tariffs[4]	345
Rider 12	56
DR Procurement	25
Total	**712**

Part V: Evolving DR Landscape

Q86. What changes has MISO implemented or are being proposed?

A86. Beginning with the planning resource auction (PRA) for the 2023/24 PY, MISO changed its resource adequacy construct from an annual to a seasonal format. The premise of the construct, where MISO establishes a planning requirement to serve

[4] Includes D3.3, D8, R1.1, R1.2 and R10

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load during peak times, and this requirement is fulfilled with resources accredited based on performance, remain unchanged. However, with the change to a seasonal construct, MISO has moved from setting a single annual planning requirement and accrediting resources with a yearly value, to establishing a planning requirement and assigning accreditation to resources for each season (spring, summer, fall and winter). Lastly, MISO is exploring various short-term and long-term accreditation and registration changes for LMRs.

Q87. Could you describe the seasonal construct that MISO implemented?

A87. Yes. MISO implemented a seasonal construct where capacity is valued differently in each MISO Season and resources are accredited based on the capacity value and performance of that resource in each season. The MISO Seasons are as follows:

- Summer: June, July, August
- Fall: September, October, November
- Winter: December, January, February
- Spring: March, April, May

Q88. Has the Company made any changes to its DR portfolio in response to the seasonal capacity construct?

A88. Yes. The Company is focused on pilots that can be available year-round and is evaluating what changes, where appropriate, could be made to programs in its current portfolio to expand their availability to other seasons.

Q89. What short-term accreditation and registration changes is MISO exploring?

A89. On a short-term basis, MISO is exploring accrediting LMRs based on actual historic availability. MISO is also exploring enhancing the auditability of its LMR availability data by asking for more frequent MISO data submittals from market participants. It is important to note that while MISO is considering making these changes, no tariff changes have been made and nothing has been filed with the Federal Energy Regulatory Commission (FERC) as of this filing.

Q90. What long-term accreditation and registration changes is MISO exploring?

A90. The long-term change that MISO is exploring is separating LMRs into emergency only and non-emergency categories. MISO is currently indicating that emergency only LMRs would require a 30-minute lead time for notification and non-emergency LMRs would have to participate in the energy market, but this proposal is subject to change as it moves through the MISO stakeholder process. Currently the Company's LMRs do not participate in the energy market. Much like the short-term accreditation and registration changes, no tariff changes have been made and nothing has been field with FERC to date.

Q91. What is the Company doing to prepare for potential MISO changes that may impact its DR portfolio?

A91. The Company will continue to keep abreast of these proposals through stakeholder meetings and will remain flexible when it comes to its DR Portfolio, understanding that these changes, if filed and approved, could change the way the Company manages and designs its DR Portfolio. As these proposals become better understood and possibly implemented, the Company will include in future DR filings any potential impacts to the Company's DR Portfolio. In addition, the Company will

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examine the potential to adjust current programs, where possible, to provide capacity for additional seasons beyond summer. The Company will also evaluate the likely LMR accreditation changes and determine if any program adjustments, such as number of events or event timing, would improve the capacity credit of its programs. Continued investment in DR is important to ensure the Company can make quick decisions regarding its programs and pilots and can, where possible, position the Company and its customers the best possible outcome as changes occur as DR resources continue to be valuable resources within MISO's capacity construct.

Part VI: DTE Insight Program

Q92. Can you please describe the DTE Insight program?

A92. Yes. DTE Insight is a comprehensive program that centers on a mobile application (DTE Insight App) integrated with the Advanced Metering Infrastructure (AMI) to help residential customers monitor and manage their energy use. Customers using the DTE Insight mobile application view their prior day's energy usage on an hour-by-hour basis, allowing customers to assess how recent weather and activities can impact their home energy usage. Customers can combine the DTE Insight App with an Energy Bridge (EB) device and obtain real-time energy information and manage connected smart devices.

Q93. How has the Company been developing and implementing the DTE Insight program since its inception?

A93. The Company has been investing in the DTE Insight program, including the additional offering of EB devices, since 2014. In 2018, the Company enhanced the program into a more robust platform, including both an updated application and an improved EB device. Starting in 2019, the Company began offering a combination of smart home features to all DTE Insight customers with the EB. With the expanded functionality of the EB device, participating customers can also control other connected smart devices (i.e., thermostats, lightbulbs, switches, plugs, and outlets). These smart devices can report energy consumption to the users and allow the users to set activities-based rules. DTE Insight is a program that aims at driving customer behavior with the goals of reducing both overall energy (gas and electricity) consumption and electricity demand at peak hours.

Q94. Has the Commission been supportive of the DTE Insight program?

A94. Yes. The Commission approved expenditures for this program in Case Nos. U-18255, U-20162, U-20561, and U-20836.

Q95. Did the Commission approve all capital costs related to the DTE Insight program in Case No. U-21297?

A95. No. The Commission disallowed $1.4 million of 2022, $0.7 million for 2023 and $0.6 million for 2024.

Q96. What was the Commission's reason for not approving the DTE Insight capital?

A96. The Commission agreed with the ALJ and Staff. "The Staff argued that capital expenditures for this program should be fully disallowed based on low engagement and participation in a nine-year-old program that the company began investing in in 2014. In this regard, the Staff averred that DTE Electric should boost engagement

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and participation in the application and in the use of EB devices before investing more money into the program." (U-21297 order, page 141)

Q97. Are you seeking recovery of the capital costs in this proceeding?

A97. Yes.

Q98. What has changed since the prior case to address the Commission and Staff's concerns with the DTE Insight capital?

A98. Unlike the prior case, the Company is not seeking recovery of capital costs related to additional energy bridges or expansion of the program. Additionally, in the prior case, "the Staff averred that DTE Electric should boost engagement and participation in the application and in the use of EB devices before investing more money into the program." (U-21297 order, page 141). As reported in Table 5 below, in the 12 months between December 31, 2022, to December 31, 2023, the DTE Insight program saw an increase of over 110,000 in authenticated household downloads and over 18,000 authenticated household with energy bridges. The 47% and 48% increase in these metrics shows customers continue to gravitate to the DTE Insight Program. To keep the program available for existing customers, the Company is seeking to recover costs related to app maintenance, software licensing, and customer support.

Q99. What are the most updated metrics regarding the development and implementation of the DTE Insight program?

A99. The Company has been focusing on increased EB utilization rate and increased customer participation and engagement while it has continued the development and implementation of the overall DTE Insight program. As shown in Table 5 below, the following metrics reflect the continuous and increasing customer engagement and participation in the program:

Table 5 – DTE Insight Metrics

	Cumulative Data as of Dec 31, 2022	Cumulative Data as of Dec 31, 2023
Authenticated Household Downloads	233,384	343,461
Authenticated Household Energy Bridges	38,093	56,519

Q100. What are the Company's planned efforts with respect to the DTE Insight program?

A100. The DTE Insight program continues to evolve from providing simple usage data to delivering actionable communications and educational content to its users. Not only does the DTE Insight App provide energy data visualization and coaching, but it also provides a comprehensive customer experience hub for energy insights, intelligence, and automations. While the DTE Insight program has been primarily utilized by energy waste reduction (EWR) customers, DTE Insight has the potential to become an effective educational tool for customers in other Company programs such as Advanced Customer Pricing Pilot, MIGreenPower, and Charging Forward. With the increasing interest, the Company expects the number of DTE Insight App users and EB requests to continue to rise.

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Q101. How much is the Company forecasting to invest in the DTE Insight program during the bridge period of January 2023 through December 2024, and in the projected test year ending December 31, 2025?

A101. The Company is forecasting to invest $1.4 million in capital expenditures during the bridge period of January 1, 2023, through December 31, 2024, and $1.6 million in capital expenditures for the projected test year from January 1, 2025, through December 31, 2025. The Company is requesting this level of investment as it is necessary to complete the plans described above, which include continued enhancement of the customer experience in the use of the program as an educational tool to support the growing participation from customers in other Company programs mentioned above. Examples of expenditures include ongoing app maintenance, software licensing, and phone and field technical support for customers. The associated projected capital expenditures are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 5, column (c) through (f).

Q102. Is the DTE Insight program included as part of the Company's DR programs and pilots and subject to the three-phase framework?

A102. No. The DTE Insight program is not subject to the evaluation and assessment established by the DR three-phase framework. General rate cases remain the appropriate regulatory proceedings for the Commission to evaluate the Company's proposed execution work and associated capital expenditures for the DTE Insight program. Therefore, the Insight program is not subject to future DR reconciliation.

Q103. Does this complete your direct testimony?

A103. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

NEAL T. FOLEY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF NEAL T. FOLEY

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Neal T. Foley (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Director, Regulatory Affairs.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science in Aerospace Engineering and a Bachelor of Science in Mechanical Engineering from the University of Michigan. I also received a Master of Science in Systems Engineering from Johns Hopkins University and a Master of Business Administration from Georgetown University.

Q4. What is your work experience?

A4. In 2007 I was employed by Lockheed Martin Corporation as a Satellite Operations Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of Financial Analysis in its Federal consulting practice. In 2014, I was hired by McKinsey & Company as an Associate Consultant, ultimately being promoted to Engagement Manager before my departure in 2017. In 2017 I was hired by DTE Energy Company as Manager of Corporate Strategy. In this role I was broadly responsible for tracking and assessing utility industry trends, executing analyses to better understand the economic impacts of emerging technologies and business

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models, and leading strategic initiatives for the Company. I was promoted to my current role as Director of Regulatory Affairs in 2020.

Q5. What are your current duties and responsibilities?

A5. My responsibilities broadly include the management of regulatory activities relative to DTE Electric's Load Research, Tariffs, Pricing, and Rate Design.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-20836	DTE 2022 Electric Rate Case
U-21376	DTE 2023 Distributed Generation Tariff Options
U-21297	DTE 2023 Electric Rate Case

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Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is twofold:

- Describe and support the key components of a proposal that the Company is putting forth in this case related to the scope and duration of its Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM)
- Describe and support the key components of a proposal that the Company is putting forth in this case to establish a Storm Restoration Cost Sharing Mechanism (SRCSM).

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibit:

Exhibit	Schedule	Description
A-33	X1	Distribution IRM Proposed Investment and In-Service Levels

Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

Distribution IRM

Q10. Can you please summarize the history of the Company's current Distribution IRM?

A10. Yes. In Case No. U-21297 the Company proposed the establishment of a Distribution IRM that would be effective starting concurrent with the forward test year in that case (i.e., December 1, 2023) and ending after roughly three years at the end of 2026. More specifically, the Company proposed the following IRM Plan Years:

- IRM Plan Year 1: December 1, 2023 to December 31, 2024
- IRM Plan Year 2: January 1, 2025 to December 31, 2025
- IRM Plan Year 3: January 1, 2026 to December 31, 2026

The Company proposed that IRM treatment be authorized for the following five capital programs focused on safety and reliability:

- Conversions
- Subtransmission Redesign & Rebuild
- Breaker Replacement
- Underground Residential Distribution (URD) Replacement
- 4.8 kV Circuit Automation

For each capital program and IRM Plan Year, the Company proposed investment levels with associated maximum in-service amounts that would be authorized for IRM treatment. Based on these investment and in-service amounts, the Company proposed an IRM revenue requirement and associated IRM surcharges for each IRM Plan Year. Importantly, the Company proposed that if it were to invest and place into service less capital than authorized, it would trigger a credit to customers. If the Company were to invest and place into service more capital than authorized, it could seek recovery of the additional investment in a future general rate case.

Finally, the Company proposed two new stakeholder processes:

- IRM Planning Process occurring before the start of each IRM Plan Year whereby the Company would make its investment plans for the upcoming IRM Plan Year available to Staff, such that Staff could raise any questions or concerns before execution of the investment plan. The investment plans would be submitted to Staff no later than two months prior to the start of each IRM Plan Year.
- IRM Reconciliation Process occurring after the conclusion of each IRM Plan Year whereby the Company would describe its actual investments, report its performance against a series of program execution metrics, and calculate any over-recovery to be returned to customers based on actual investment and plant in-service.

In its proposal the Company highlighted four benefits that would be immediately realized with the establishment of the IRM; specifically:

- Certainty of investment in key distribution capital programs;
- Greater transparency into both the Company's investment plans and its execution of those plans;
- Additional opportunities for Staff to review and provide input on the Company's investment plans; and
- Increased accountability for the Company through the reporting of new program execution metrics.

Further, the Company highlighted that a potential future benefit of the IRM is to extend the time between contested rate cases.

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In its December 1, 2023 order in that case (December 2023 Order), the Commission stated that it "finds that there is value in the company's proposal, with some limitations." (page 289). As such, it elected to approve the Company's proposed IRM with modifications. Specifically, the Commission ordered the following modifications to the Company's proposal:

- The Company shall submit its annual IRM Investment Plan no later than four months prior to the start of each IRM Plan Year and it shall be submitted to all intervening parties in the Company's most recently filed general rate case.
- The Company shall schedule and provide a forum, no later than two months before the start of the IRM plan year, for Staff and intervening parties to raise any questions or concerns that they have before execution of the plan begins.
- The annual IRM reconciliation shall be filed as a contested case proceeding, noting that:

  "…a contested reconciliation process will provide additional opportunities for input from interested parties. Further, developing a record in a contested proceeding will provide even greater transparency and opportunity for review of the reasonableness and prudence of the company's expenditures, as well as accept input to address equity concerns such as those raised by the DAAOs to avoid racialized disparities in service." (page 290)
- The Company shall remove any allocation of IRM costs from transmission level customers.

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Finally, the Commission elected to approve only IRM Plan years 1 and 2. In declining to approve the Company's proposed IRM Plan Year 3, the Commission provided the following guidance:

"…there is ongoing discussion regarding [Performance Based Ratemaking] in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM." (page 289)

Q11. What is the current status of the Company's Distribution IRM?

A11. As discussed above, the Commission's December 2023 Order established the IRM effective starting on December 1, 2023 (with surcharges being implemented on December 15, 2023). In that Order, the Commission acknowledged the challenged timing of IRM Plan Year 1, stating:

"Regarding the time constraints for the first investment recovery mechanism plan year recognized in this order, the company shall use best efforts to provide its investment recovery mechanism plan as soon as practicable that will in turn, allow the company to schedule the forum as soon as practicable." (page 375)

As such, the Company submitted its IRM Year 1 Investment Plan to stakeholders on February 7, 2024, and subsequently presented the plan during a stakeholder forum on February 23, 2024.

Q12. What is the Company proposing in this case related to its Distribution IRM?

A12. The Company is proposing to extend the IRM through calendar years 2026 and 2027. The Company's proposal does not include any modifications to what was previously approved for 2024 and 2025, although it does offer an alternative scenario for 2025 that would increase the amount of capital authorized for IRM treatment during that year, as described later in my testimony.

As part of the extension, the Company is proposing two adjustments to the capital programs previously authorized for IRM treatment. Specifically, the Company is proposing:

- Starting in 2026, Pole and Pole Top Maintenance and Modernization (PTMM) be authorized for IRM treatment. Company Witness Elliott Andahazy provides additional support for this proposed modification in her testimony; and
- Starting in 2026, the scope of the automation program be modified from "4.8 kV Circuit Automation" to "Distribution Automation." Company Witness Hartwick provides additional support for this proposed modification in her testimony.

For 2026 and 2027, the Company is proposing a level of capital investment and maximum in-servicing amount for each program and year. The full detail of the Company's proposed investment and in-service levels for 2026 and 2027 is captured in Exhibit A 33, Schedule X1, and is summarized in Table 1 below.

Table 1 – Proposed IRM Investment Levels ($M)

	Previously Approved Investment		Proposed Investment	
Capital Program	**2024**	**2025**	**2026**	**2027**
Conversions	1.6	185.8	190.0	240.0
Subtransmission Redesign & Rebuild	5.5	53.8	55.0	65.0
Breaker Replacement	13.7	12.6	15.0	15.0
URD Replacement	14.6	13.5	15.0	20.0
Distribution Automation[1]	26.4	24.4	105.0	180.0
Pole & Pole Top Maintenance & Modernization	n/a	n/a	150.0	200.0
Total	**61.9**	**290.1**	**530.0**	**720.0**

The Company is not proposing any modifications to the annual planning process, annual reconciliation process, or underlying mechanics of the Distribution IRM approved by the Commission through its December 2023 Order.

In their testimony, Company Witness Vangilder supports the revenue requirement associated with the Company's proposed IRM investments, Company Witness Maroun supports the cost-of-service treatment, and Company Witness Willis supports the rate design of the surcharges to collect the allocated revenue requirement.

[1] Previously 4.8 kV Circuit Automation

Q13. How is the Company's proposed extension in this case different than the 2026 IRM investment proposed in Case No. U-21297?

A13. In Case No. U-21297, the Company proposed 2026 IRM investment of $532.7 million, including the following program-specific investments:

- Conversions: $371.6 million
- Subtransmission Redesign & Rebuild: $107.6 million
- Breaker Replacement: $14.0 million
- URD Replacement: $15.0 million
- 4.8 kV Circuit Automation: $24.4 million

In the current case, the Company's proposed total investment for 2026 is similar at $530.0 million, although the investment mix is different. More specifically, the Company's proposal in this case reflects increasing emphasis on Distribution Automation and PTMM for the IRM. Company Witnesses Hartwick and Elliott Andahazy further support the increasing emphasis on these programs in their testimonies.

Q14. Are there other issues before the Commission that impacted the Company's decision to propose an extension of its Distribution IRM?

A14. Yes. The Company is proposing an extension of its Distribution IRM to ensure its continued and efficient operation while pending Case No. U-21400 related to Performance Based Ratemaking (PBR) and pending Case No. U-21305 related to the Company's Distribution System Audit can progress and ultimately conclude. Absent an extension granted in this case, the existing IRM will cease at the end of 2025 and could only be re-established through a Commission order in a future case.

Such stopping and restarting of the IRM and its associated processes could lead to inefficiencies and reduce the ability to improve upon the process through stakeholder feedback. Importantly, the proposed extension will ensure that the customer and stakeholder benefits realized through the IRM do not lapse.

With that said, the Company also acknowledges the Commission's desire for future iterations of the IRM to potentially incorporate the findings of pending Case No. U-21400 related to PBR and pending Case No. U-21305 related to the Company's Distribution System Audit. The Company supports the Commission's desire to incorporate findings from these cases into future iterations of the IRM as discussed later in my testimony.

At the same time, to make the IRM successful there must be robust, transparent, and repeatable processes in place that give all stakeholders confidence that the IRM is working as planned and the intended benefits are being realized. Given that many of these processes are new, including the IRM planning and reconciliation processes, having the IRM and its associated processes lapse at the end of 2025 would challenge the ability of stakeholders to gain experience with the IRM and identify opportunities for improvement.

For example, absent an extension approved in the current case, the Company will not submit an IRM Investment Plan for 2026 (otherwise due no later than August 31, 2025) or hold a stakeholder forum on its 2026 plans since the IRM will not yet have been authorized for 2026.

As such, an extension is appropriate to avoid a lapse in the IRM and its associated benefits, while allowing for the cases related to PBR and the Company's Distribution System Audit to conclude.

Q15. What is the status of Case No. U-21400 related to PBR?

A15. In its April 24, 2023 Order in Case No. U-21400 (April 24 Order), the Commission directed Staff to convene a Financial Incentives and Disincentives Workgroup to study PBR and to file a report of the workgroup's investigations and findings by December 31, 2023. Among other things, the Commission directed that:

> *"…an initial focus of the Financial Incentives and Disincentives workgroup shall include developing appropriate metrics relating to reliability including, but not limited to, SAIDI (including and excluding MEDs), SAIFI, CEMI, CAIDI, and resilience, including, but not limited to, downed wire response and the frequency and duration of outages during extreme weather, and shall use the recently updated Service Quality rules as a baseline."* (page 12)

and

> *"After developing metrics around distribution performance, the workgroup shall explore rate structures and the methods by which incentives and disincentives may be applied."* (page 12)

In its August 23, 2023 Order in the same case, the Commission released its initial PBR straw proposal and invited comments from interested stakeholders to be submitted by September 22, 2023 with reply comments to be submitted by October 20, 2023. The Commission also directed Staff to convene a stakeholder session following the initial comment period to discuss the straw proposal and alternative approaches.

In response, the Company submitted initial comments on September 22, 2023 and reply comments on October 20, 2023. The Company also participated in the stakeholder session that was held on October 10, 2023, including presenting its perspectives related to the initial straw proposal.

On November 29, 2023, the Commission released a revised straw proposal and held a stakeholder session on November 30, 2023 to discuss the revised proposal and gather any initial feedback from attendees. The Company attended the November 30, 2023 stakeholder session.

On December 19, 2023 Staff filed in the same docket its status report required by the Commission's April 24 Order. In its report Staff recommended that the Commission formally invite comments on its revised straw proposal and indicated it would hold an additional stakeholder session on February 12, 2024.

In its December 21, 2023 Order in the same case, the Commission adopted the Staff's recommendation and invited comments from interested stakeholders on the revised straw proposal to be submitted by February 2, 2024 with reply comments to be submitted by March 1, 2024. The Commission further directed Staff to submit a status report on the workgroup's investigations and findings no later than May 3, 2024.

In response, the Company submitted comments on the revised straw proposal on February 2, 2024, participated in the stakeholder session on February 12, 2024, and submitted reply comments on March 1, 2024.

At the time of this filing, the Company is awaiting the release of Staff's second status report and any additional guidance from a Commission order in the case.

Q16. How is the Company planning to incorporate the findings from Case No. U-21400 into potential future iterations of its Distribution IRM?

A16. If an order in Case No. U-21400 is received in mid-2024, and barring any future guidance from the Commission to the contrary, the Company plans to propose a PBR mechanism in its first general rate case after the current case. Given that IRM proposals are made during general rate cases, the Company believes that a general rate case is the most appropriate venue to establish PBR such that it can be considered together with a potential future IRM proposal. In that rate case filing, the Company could address how a potential future IRM proposal is informed and/or complimented by an application of PBR.

This approach is consistent with Staff's December 19, 2023 status report in which it stated:

"This revised proposal anticipates that a contested case proceeding would follow this workgroup process. The final decision in the contested case would implement performance metrics for each utility." (page 6)

Q17. What is the status of Case No. U-21305 related to the Company's Distribution System Audit?

A17. The Distribution System Audit was formally launched in August 2023 with the awarding of a contract to Liberty Consulting Group for the comprehensive independent audit of Consumers Energy and DTE Electric.

On December 20, 2023, The Liberty Consulting Group submitted its "Utility Distribution Audit Status Report" in compliance with the terms of its contract. The report summarized its progress to date on the audits of Consumers Energy and DTE Electric but did not include any preliminary findings or recommendations.

At the time of the filing of this case, the audit is ongoing. A final report is expected in late summer or early fall of 2024.

Q18. How is the Company planning to incorporate the findings from Case No. U-21305 into potential future iterations of its Distribution IRM?

A18. The Company anticipates that at the conclusion of the Distribution System Audit there will be a series of recommendations from Liberty Consulting Group. The Company plans to carefully consider these recommendations and, as determined appropriate by the Company, incorporate them into future Distribution Grid Plans (DGPs) and capital investment plans.

Likewise, future IRM proposals would incorporate the recommendations from the Distribution System Audit where appropriate. For example, while the Company cannot predict what those recommendations will be, it is possible that the Company may propose changes to either the programs or the investment levels authorized for IRM treatment based on Liberty Consulting Group's findings.

If a final report is submitted by Liberty Consulting Group in late summer or early fall of 2024, the Company anticipates that there would be sufficient time to incorporate the recommendations from the audit where appropriate into an IRM proposal in the first rate case filed after the current rate case.

Q19. Given the timing of these other proceedings, why is the Company proposing a two-year extension of the IRM?

A19. The Company believes a two-year extension is most appropriate to (1) avoid a lapse in the IRM and its associated benefits, (2) provide greater certainty related to use of the IRM as a regulatory mechanism, and (3) maintain the ability to incorporate findings from the pending cases related to PBR and the Distribution System Audit into future iterations of the IRM.

While a one-year extension would likely allow the pending cases related to PBR and the Distribution System Audit to conclude, it would also create additional uncertainty as to the long-term disposition of the IRM. As discussed previously, to make the IRM successful there must be robust, transparent, and repeatable processes in place that give all stakeholders confidence that the IRM is working as planned and the intended benefits are being realized. Uncertainty related to the

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ongoing use of the IRM challenges the establishment and evolution of the IRM and its associated processes as stakeholders cannot effectively plan for its long-term use.

Q20. In addition to the proposal described above, would the Company support an increase in the amount of capital authorized for IRM treatment in 2025?

A20. Yes. As described previously, the Company's proposed IRM extension does not impact the authorization for IRM treatment previously granted by the Commission for 2024 and 2025.

However, increasing the amount of capital authorized for IRM treatment in 2025 would also increase the benefits associated with the IRM. For example, increasing the amount of capital authorized for IRM treatment will also increase the certainty of investment of this incremental IRM capital for its intended purpose, with any under-investment triggering a refund to customers.

As such, the Company would support increasing the amount of capital authorized for IRM treatment in 2025 beyond what was previously authorized as a way to also increase the benefits associated with the IRM. If the Commission were to find such an approach appropriate, the Company's request for recovery of 2025 capital expenditures through base rates could be reduced by an amount equal to the additional IRM authorization.

Q21. Has the Company identified investments it believes would be appropriate for IRM treatment if the Commission were to expand IRM authorization beyond what was previously approved for 2025?

A21. Yes. The Company has identified four areas of capital investment it believes are appropriate for IRM authorization in 2025 (beyond what was previously authorized):

- Distribution Automation - $125.6 million of proposed 2025 investment[2]
- PTMM - $121.0 million of proposed 2025 investment[3]
- 4.8 kV Hardening - $125.0 million of proposed 2025 investment[4]
- Frequent Outage Program (CEMI) - $62.5 million of proposed 2025 investment[5]

As mentioned above, if the Commission were to authorize, either in full or in part, the above capital programs and investment amounts for IRM treatment in 2025, that capital could be removed from the Company's base rate recovery request.

Storm Restoration Cost Sharing Mechanism (SRCSM)

Q22. How are storm restoration O&M costs currently projected and recovered?

A22. Company Witness Kryscynski supports the calculation of projected storm restoration O&M expenses in his testimony and Exhibit A-13, Schedule C5.6, Page 2 of 2, Lines 1-8.

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[2] Company Witness Hartwick (Exhibit A-12, Schedule B5.4, Page 17 of 26, Line 2); this represents automation investment beyond what was previously approved for IRM treatment for 2025
[3] Company Witness Elliott Andahazy (Exhibit A-12, Schedule B5.4, Page 13 of 26, Line 13)
[4] Company Witness Elliott Andahazy (Exhibit A-12, Schedule B5.4, Page 13 of 26, Line 12)
[5] Company Witness Elliott Andahazy (Exhibit A-12, Schedule B5.4, Page 13 of 26, Line 15)

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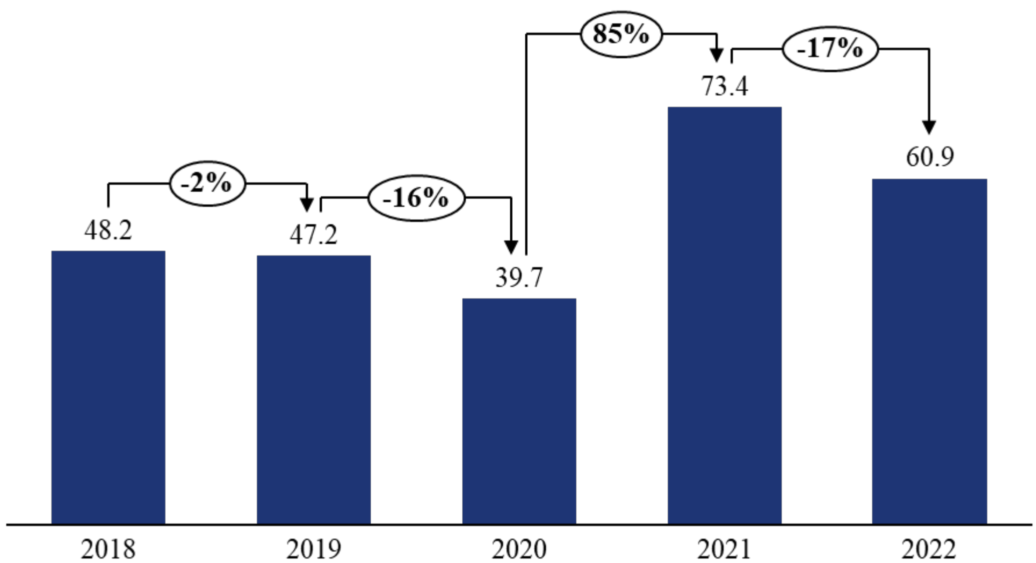
As described by Company Witness Kryscynski, projected storm restoration O&M expenses are based on a five-year trailing average (i.e., historical test period and preceding four years), adjusted for inflation. Based on the five-year trailing average methodology, for the forward test period in this case, the Company is projecting $64.5M of storm restoration O&M expenses. These projected expenses are proposed to be recovered though base rates as they have been historically.

Q23. Does the Company have any concerns with the current method for storm restoration O&M expense recovery?

A23. Yes. The current approach to storm restoration O&M expense recovery does not address the uncertainty and variability of these expenses in any given year and therefore puts both customers and the Company at risk of either over-recovering or under-recovering storm restoration O&M costs.

Figure 1 below captures actual storm restoration O&M expenses incurred by the Company between 2018-2022 as supported by Company Witness Kryscynski.

Figure 1 - Actual Storm Restoration O&M Expense ($ million)[6]



As can be seen in the chart, year-over-year changes to actual costs are volatile, ranging from a 17% decrease in costs between 2021 and 2022 to an 85% increase in costs between 2020 and 2021.

In years when actual costs are less than what was authorized for recovery, customers would pay more in rates than the actual storm restoration costs incurred in that year. In years when actual costs are greater than what was authorized for recovery, the Company must absorb any difference. Either way, the current approach to storm restoration O&M cost recovery risks misalignment between what is recovered from customers and the actual expenses incurred by the Company.

Q24. Does the Company expect storm restoration O&M expenses to remain uncertain and volatile?

[6] Exhibit A-13, Schedule C5.6, Page 2 of 2, Line 2

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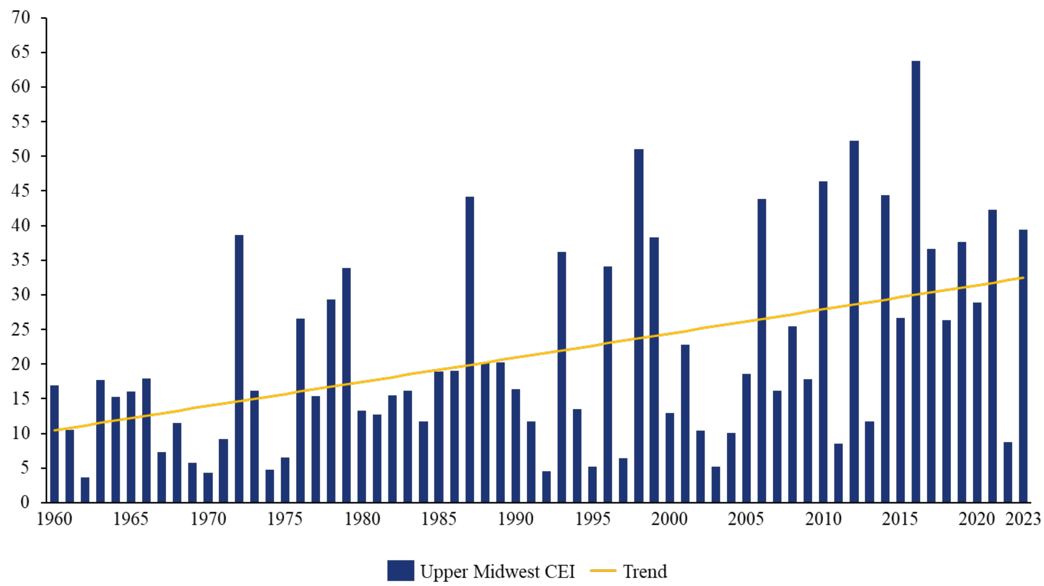
A24. Yes. Storm restoration expenses are impacted by the frequency and duration of extreme weather events. Figure 2 below captures data from the National Oceanic and Atmospheric Administration (NOAA) on the Upper Midwest[7] Climate Extremes Index (CEI)[8]. The Upper Midwest CEI measures the portion of time that the Upper Midwest was subject to extreme weather during a given year. A CEI value of 0% indicates that no portion of the Upper Midwest was subject to any of the extreme conditions considered in the index during the year. In contrast, a value of 100% would mean that the entire Upper Midwest had extreme conditions throughout the year. The CEI analysis considers:

- Maximum and minimum temperature
- Daily precipitation
- Monthly Palmer Drought Severity Index (PDSI)

[7] Upper Midwest includes Michigan, Wisconsin, Minnesota, and Iowa
[8] https://www.ncei.noaa.gov/access/monitoring/cei/

Figure 2 - Upper Midwest Climate Extremes Index (CEI)



As can be seen in the chart, not only is there is a clear trend toward more extreme weather in the Upper Midwest, but there can be significant variation from year to year in the amount of extreme weather experienced in the region. For example, just considering the last five years (i.e., 2019-2023) the Upper Midwest CEI has fluctuated from a high of 42.3% in 2021 to a low just one year later of 8.8% in 2022.

Simply put, the amount of extreme weather experienced by the Company cannot be accurately predicted in advance and therefore there will continue to be uncertainty related to the level of storm restoration O&M expense for any given year.

Q25. What is the Company proposing related to storm restoration O&M expense recovery in this case?

A25. The Company is proposing that the Commission authorize the Storm Restoration Cost Sharing Mechanism (SRCSM), becoming effective at the start of the projected test year in this case (i.e., January 1, 2025).

The Company proposes that the SRCSM operate as follows:

- The calculation of projected storm restoration O&M expenses continues to follow the five-year trailing average methodology as supported by Company Witness Kryscynski in this case; likewise, these projected amounts continue to be authorized for recovery from customers through base rates.
- At the conclusion of each calendar year, actual storm restoration O&M expenses are compared to the amount authorized to be recovered from customers in base rates; for years in which the amount authorized for recovery through base rates changes (e.g., a general rate case order is received and becomes effective mid-year), the authorized recovery amount would be calculated on a prorated basis to reflect the timing and amount of the updated authorization.
- Any difference between actual storm restoration O&M expenses and those authorized for recovery is equally shared between the Company and its customers; specifically:
    - If actual storm restoration O&M expenses are less than projected, the Company returns 50% of the difference to customers by recording that amount as a Regulatory Liability.

- If actual storm restoration O&M expenses are more than projected, the Company recovers 50% of the difference from customers by recording that amount as a Regulatory Asset.

- Regulatory Assets and/or Liabilities accumulate between general rate cases until a subsequent general rate case when any net Regulatory Liability or Regulatory Asset is addressed.

For example, if the Company's projected costs for 2025 of $64.5M were to be fully approved, but actual 2025 storm restoration O&M expenses were only $40.0 million, then the Company would record a Regulatory Liability of $12.3 million to be returned to customers in a subsequent rate case. The $12.3 million is 50% of the difference between approved costs included in base rates (i.e., $64.5 million) and actual costs (i.e., $40.0 million).

Q26. Has the Commission provided any recent guidance on the use of alternative storm restoration expense recovery mechanisms?

A26. Yes. In its most recent electric rate case (Case No. U-21389), Consumers Energy proposed the Symmetric Performance Incentive Mechanism (SPIM). As described by Consumers Energy Witness Houtz in her direct testimony, the SPIM "…would return service restoration costs below what is set in rates back to customers and cover costs for the Company in excess of base rates." (page 24) Importantly, Witness Houtz describes the use of a "deadband" in the proposed SPIM. According to Witness Houtz, if expenses are below what is set in rates a portion would be returned to customers "with the Company retaining the first 10%." (page 24) If expenses are above what is set in rates, a portion would be recovered from customers "with the first 10% being offset by the Company." (page 24)

In its March 1, 2024 Order in that case (March 2024 Order), the Commission declined to adopt Consumers Energy's proposed SPIM. In doing so, the Commission provided in part the following guidance:

> *"…the Commission finds that [Consumers Energy] has not demonstrated that the SPIM will sufficiently control service restoration expenses as claimed by [Consumers Energy]."* (page 174)

and

> *"…the SPIM does not incentivize [Consumers Energy] to reduce service restoration expenses more than 10% below that approved in rates. Furthermore, there is no evidence demonstrating that the 10% offset would adequately deter [Consumers Energy] from passing through large cost increases to customers. Finally, the Commission finds that approval of the mechanism is premature given the ongoing audit in Case No. U-21305."* (page 175)

Q27. Is the Company's proposed SRCSM responsive to the Commission's guidance in Case No. U-21389?

A27. Yes. As the Commission pointed out in its March 2024 Order, the use of a deadband could result in the utility only having an incentive to control costs when inside the deadband. If actual costs are outside the deadband then the utility's financial incentive to control costs could be diminished because costs will either be returned to customers (in the event that actual costs are less than authorized in base rates) or recovered from customers (in the event that actual costs are greater than authorized in base rates).

Given the Commission's guidance, the Company is not proposing the use of a deadband. Instead, the Company is proposing the equal sharing of costs that differ from those authorized for recovery in base rates. The sharing of costs ensures that the Company has a strong incentive to control costs regardless of what actual costs are for a given year. Specifically, if actual costs are greater than projected, the Company is incentivized to control costs because it must absorb 50 cents of every incremental dollar that is spent. If actual costs are less than projected, the Company is still incentivized to control costs because it is allowed to retain 50 cents of every incremental dollar that is saved.

Q28. Would the establishment of the SRCSM impact the Company's ability or incentive to act on any future recommendations resulting from the Distribution Audit?

A28. No. The approval of the SRCSM would not prevent the Company from acting on any future recommendations resulting from the Distribution Audit. As discussed previously, the proposed SRCSM incentivizes the Company to control storm restoration O&M costs regardless of what total costs are for a given year. As such, the proposed SRCSM encourages the Company to implement any appropriate actions faster such that it can better control costs.

Q29. Does this complete your direct testimony?

A29. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARGARET E. GUILLAUMIN

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Margaret E. Guillaumin (she/her/hers). My business address is One Energy Plaza, Detroit MI, 48226. I am employed by DTE Electric Company (DTE Electric or Company) as Plant Director in the Energy Supply organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. My formal education consists of a Bachelor of Science degree in Chemical Engineering from Michigan Technological University. I have also completed several Company sponsored courses and have attended various seminars to further my professional development with DTE Electric.

Q4. What work experience do you have?

A4. I began my employment with DTE Electric in July 2003 in the engineering department at River Rouge Power Plant. Throughout my career with DTE Electric I have received various promotions with increasing levels of responsibility. These positions included several engineering roles at the St. Clair Power Plant beginning in November of 2003, Supervisor of Chemical Engineering for DTE Electric's fossil power plants in 2010, Manager of Laboratory and Field Support in 2012, Fuel Supply Manager at St. Clair Power Plant in 2014, and St. Clair Power Plant Maintenance Manager in 2016. In October of 2017, I was promoted to Plant Manager, Greenwood Energy Center, responsible for all day-to-day operation, maintenance, and engineering for the facility. In April 2019, I was given additional

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responsibilities that included Peakers and Ludington. In this expanded role I added to my responsibilities the operation, maintenance, and engineering of DTE Electric's natural gas and fuel oil Peakers as well as responsibilities for DTE Electric's interest in the Ludington Pumped Storage facility. In April of 2022, I was appointed Plant Manager, Blue Water Energy Center, where I was responsible for transitioning the newly constructed facility through final commissioning activities to commercial operation. Following the commercial operation date, I was responsible for the day-to-day operation, maintenance, and engineering of the facility.

Q5. What are your current duties and responsibilities?

A5. In April 2023, I was promoted to Plant Director, Operations Performance. In this role my responsibilities include periodic outage planning and execution for DTE Electric's fossil power plants, strategic planning and long-term generation strategy, asset maintenance planning, and oversight of the St. Clair, Trenton Channel and River Rouge Power Plants during decommissioning. I also have responsibilities for approving capital projects as a voting member of the Capital Governance Board.

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Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to support the reasonableness and prudency of the operations and maintenance (O&M) and capital expenditures for Energy Supply steam power generation, hydraulic power generation (Ludington), and other power generation for the historical test year ended December 31, 2022, the 24-month bridge period ending December 31, 2024, and the 12-month projected test period ending December 31, 2025. Although Energy Supply currently operates and maintains DTE Electric's fleet of wind and solar assets, costs of these assets are managed in other regulatory proceedings. Therefore, throughout my testimony when I refer to Energy Supply assets, I am referring to the fossil and energy storage assets, including hydraulic storage and Battery Energy Storage Systems (BESS). No part of my testimony includes Energy Supply renewable generation wind and solar assets as they are handled in other regulatory filings as noted above. I also address the following additional topics in my testimony:

1) I explain forecasted changes affecting generation ratings on a yearly basis for 10 years looking forward (2022 through 2032). The changes are associated with projected retirements of current generating assets, the addition of new Energy Supply assets, as well as changes to existing units.

2) I provide a review of Energy Supply coal-fired and combined cycle unit availability for the most recent five years of actual performance and the next five years projected. In addition to discussing availability, I will also discuss the planned and unplanned outage performance for these same timeframes.

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3) For capital expenditures, I discuss how the Environmental Protection Agency's (EPA) Steam Electric Effluent Limitation Guidelines (ELG) Rule affects required coal-fired generation investments.
4) I then provide details of the historical 2022 level of expenditures on a plant level basis and provide forecasts of expenditures to be incurred from January 1, 2023 through December 31, 2025. This data shows the levels of expenditures related to routine maintenance, environmental compliance requirements, and expenditures related to safety and general reliability that have been and will be made over the timeframes of this case. These discussions on capital expenditures cover the Energy Supply generation and hydraulic plants including the coal-fired and gas-fired steam units, the Ludington pumped storage units, the Blue Water Energy Center combined cycle unit, the peaking units, and new energy storage to be added.
5) I discuss significant reductions to capital expenditures planned for Monroe Units 3 and 4 in light of their accelerated retirement dates.
6) I support the multiple known and measurable changes in Energy Supply's O&M expenses that will span the timeframe from the 2022 historic test year in this case to the projected test year, ending December 31, 2025. These known and measurable changes include:
   - Retirements of St. Clair and Trenton Channel Power Plants
   - Blue Water Energy Center commercial operations
   - Slocum BESS commercial operations
   - Retirements of Northeast 11-1, River Rouge 11 1-4, Slocum 11 1-5, and St. Clair 12 1-2 peakers and suspension of operation of Fermi 11-3 and Fermi 11-4 peakers

- Corporate memberships excluded from rates.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-6	F1	Planned Long Range Generation Changes (Steam, Hydraulic & Other)
A-6	F2	Energy Supply Coal and Combined Cycle Unit Performance
A-12	B5.1	Projected Capital Expenditures – Steam, Hydraulic, and Other Power Generation
A-12	B5.1.1	Commission-requested Monroe FGD Asset Preservation Project Report
A-13	C5.1	Projected Operation and Maintenance Expenses – Steam Power Generation
A-13	C5.4	Projected Operation and Maintenance Expenses – Hydraulic Power Generation
A-13	C5.5	Projected Operation and Maintenance Expenses – Other Power Generation

Q8. Were these exhibits prepared by you or under your direction?

A8. Yes, they were.

Q9. How is your testimony organized?

A9. My testimony consists of the following three (3) parts:

Part I	Energy Supply Plant Capacity and Availability
Part II	Energy Supply Capital Expenditures
Part III	Energy Supply Operation and Maintenance Expenses

Part I – Energy Supply Plant Capacity and Availability

Energy Supply Net Summer Installed Capacity

Q10. Can you provide an overview of DTE Electric's Energy Supply assets?

A10. As of January 1, 2022, the Company's owned fossil and hydraulic generation based on installed summer capacity ratings totaled 9,565 MW and was comprised of:

Rated Capacity (Summer) as of 1/1/2022

Fossil Steam	6,445 MW
Peaking Plant	2,032 MW
Pumped Storage	1,088 MW
Total Fossil/Hydraulic System	9,565 MW

The Company's 6,445 MWs of fossil steam plant includes coal-fired units that provided 5,660 MW of capacity and a gas-fired unit that provided an additional 785 MW of capacity as shown below:

Rated Capacity as of 1/1/2022

Coal-fired Steam Plants	Net Summer Capability	No. Units
Belle River (DTE ownership)	1,034 MW	2
Monroe	3,066 MW	4
St. Clair	1,065 MW	4
Trenton Channel	495 MW	1

Total Coal-fired Capacity (steam)	5,660 MW	11

Gas-fired Steam Plants	Net Sumer Capability	No. Units
Greenwood	785 MW	1
Total Gas-fired Capacity (Steam)	785 MW	1

The Michigan Public Power Agency (MPPA) is joint owner of Belle River Power Plant and its ownership entitlement is 18.61% (236 MW) of the plant. The MPPA ownership of Belle River Power Plant is not included in the 1,034 MW shown above.

DTE Electric's peaking plants, along with DTE Electric's ownership share of the Ludington Pumped Storage facility, jointly owned with Consumers Energy, are shown below:

Rated Capacity as of 1/1/2022

Peaking and Pumped Storage	Net Summer Capability	No. Units
Gas/Oil Combustion Turbines (11 locations)	1,904 MW	37
Diesel Generators (10 locations)	128 MW	46
Total Peaking Capacity	2,032 MW	83
Ludington Pumped Storage	1,088 MW	6
Total Pumped Storage/Peaking Capacity	3,120 MW	89

Line No.

Q11. Can you provide a summary of Exhibit A-6, Schedule F1 titled "Planned Long Range Generation Changes (Steam, Hydraulic, & Other) Years 2022 through 2032"?

A11. Exhibit A-6, Schedule F1 provides the 2022 actual generation rating changes and a 10-year projection of the forecasted changes at Energy Supply units through 2032. Changes are based on the forecasted timing of upcoming unit retirements, development of new Energy Supply assets, and modifications to existing assets. This exhibit does not include new or existing renewable resources.

Q12. Can you please explain the yearly generation facility changes shown on Exhibit A-6, Schedule F1 for 2022-2032?

A12. The changes for 2022 are shown on lines 1 through 6 of Exhibit A-6 Schedule F1. In 2022, the Company retired St. Clair Units 2, 3, 6, and 7, representing a combined 1,065 MW of coal-fired summer-rated capacity. Trenton Channel Unit 9, a coal-fired unit with a summer capacity rating of 495 MW, also retired. The Blue Water Energy Center, a combined cycle gas turbine (CCGT) power plant with a summer-rated capacity of 1,127 MW, commenced commercial operations in June of 2022. The Ludington Unit 3 upgrade for an additional 34 MW of generation capacity was also completed.

The changes for 2023 are shown on lines 8 and 9 of Exhibit A-6 Schedule F1. Northeast 11–1 peaker (15 MW) experienced significant in-service damage in 2019 and was formally retired in 2023. Additionally, the Slocum peakers (14 MW) were retired in 2023 to facilitate the construction of the new Slocum Battery Energy Storage System (BESS).

The forecasted changes for 2024 are shown on lines 11 through 13 of Exhibit A-6 Schedule F1. The Company plans to retire the River Rouge 11 peakers and the St. Clair 12 peakers, representing 16 MW of summer peaking capacity. Additionally, the Slocum Battery Energy Storage System (BESS), with a rating of 14 MW, is projected to be completed in 2024, replacing the peakers previously located at the site that were retired in 2023.

The forecasted changes for 2025 are shown on lines 15-16 of Exhibit A-6 Schedule F1. The Company plans to suspend the operations of the Fermi 11-3 and 11-4 peakers, representing 25 MW of summer peaking capacity, and Belle River Unit 1 is projected to convert from coal-fired to natural gas-fired operations.

The forecasted changes for 2026 are shown on lines 18-19 of Exhibit A-6 Schedule F1. In 2026, the Trenton Channel 220 MW BESS is projected to commence operation and Belle River Unit 2 is projected to convert from coal-fired to natural gas-fired operations.

No changes are forecasted for 2027 in Exhibit A-6 Schedule F1.

The forecasted changes for 2028 are shown on lines 23-24 of Exhibit A-6 Schedule F1. In 2028, consistent with the final Order dated July 26, 2023, in the Company's 2022 IRP, Case No. U-21193, the Company projects retiring Monroe Units 3 and 4, representing a combined 1,535 MW of coal-fired summer-rated capacity and commencing operation of a 275 MW BESS.

No changes are forecasted in Exhibit A-6 Schedule F1 from 2029 through 2031.

The forecasted change for 2032 is shown on line 32 of Exhibit A-6 Schedule F1. In 2032, consistent with the final Order dated July 26, 2023, in the Company's 2022 IRP, Case No. U-21193, the Company projects retiring Monroe Units 1 and 2, representing a combined 1,531 MW of coal-fired summer-rated capacity.

Energy Supply Plant Performance

Q13. How is the Company's Energy Supply plant performance monitored and calculated?

A13. Energy Supply utilizes Equivalent Availability Factor (EAF), Planned Outage Factor (POF), and Random Outage Factor (ROF) to monitor overall unit performance. EAF is equal to 100 minus the POF minus ROF. Equivalent availability is equal to total possible megawatt-weeks minus planned outage megawatt-weeks minus random outage megawatt-weeks (including full and partial derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks are calculated by multiplying the net demonstrated capacity of the unit by the weeks in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to the equivalent number of weeks in the time-period that the unit is not available due to scheduled maintenance multiplied by the capacity that is out of service. Random outage megawatt-weeks is the number of weeks of unit unavailability caused by an outage or derate that is not planned or scheduled, multiplied by the capacity that is out of service.

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Q14. What are the major drivers of unit unavailability?

A14. There are three major drivers of unit unavailability: (1) planned full unit or periodic maintenance outages, (2) unplanned or random unit outages, and (3) derates or partial unit outages which can be planned or unplanned.

Planned full unit outages and planned derates are those outages for which the Company has developed long range maintenance plans designed to sustain unit performance, install required environmental systems, and proactively address emerging reliability issues. Unplanned unit outages and unplanned derates are those that occur due to either reliability issues common across the industry or unusual events which are unique to a specific DTE Electric plant or unit.

Q15. Can you explain the Company's 2022 total Energy Supply plant availability performance?

A15. The EAF for Energy Supply steam, hydraulic, and other power generation assets was 74.1% for the 2022 historic period. The 74.1% equivalent availability was the result of a 13.2% ROF and a 12.6% POF. In 2022, Energy Supply assets included Belle River, Blue Water, Greenwood, Monroe, St. Clair, Trenton Channel, Ludington, and peaker power plants. Energy Supply availability for 2022 was reduced by several planned major overhaul maintenance outages completed on Belle River Unit 1, Monroe Unit 2, and multiple peaker units. Less comprehensive planned outages were completed on many units to prepare units for or recover from high peak load summer operations.

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Q16. What was the equivalent availability specific to the coal-fired and combined cycle units within Energy Supply in 2022?

A16. As shown on line 4 of Exhibit A-6, Schedule F2, coal-fired and combined cycle plants had an equivalent availability of 72.7% in 2022 as a result of a 14.7% ROF and a 12.6% POF for those units. Coal-fired plants included the Belle River, Monroe, St. Clair, and Trenton Channel power plants. The Blue Water Energy Center combined cycle plant is also included in the availability metrics.

Q17. How does the forecasted future coal-fired and combined cycle unit availability compare to the actual historical availability?

A17. As shown in Exhibit A-6, Schedule F2, the average coal-fired and combined cycle unit availability for 2019-2023 was 73.4% while the forecast of average coal-fired and combined cycle unit availability for 2024-2028 is 80.0%. The older and less reliable coal-fired power plants were retired by 2022, resulting in an increase in availability for 2023 and beyond.

Part II – Energy Supply Capital Expenditures

Q18. Can you please provide an overview of your Part II discussion?

A18. Yes. In this section of my testimony, I will discuss the following:

- Capital Planning Process
- ELG Rule Compliance
- 2022-2025 Capital Projects Summary
- Non-Routine Capital Expenditures
- Routine Capital Expenditures

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- Reductions to Monroe Unit 3 and 4 Capital Expenditures and Updates to the Capital Projects Planned
- Allowance for Funds Used During Construction (AFUDC) Estimate
- Removal Costs, Plant in Service and CWIP schedule

Capital Planning Process

Q19. Can you explain Energy Supply's capital planning process?

A19. Yes. Capital projects are initiated to support safety, regulatory requirements, environmental compliance, plant-level reliability plans, Original Equipment Manufacturer (OEM) recommendations, or the engineering recommendations of Energy Supply's equipment and system experts. Capital expenditure requests require the development of a plant management approved project request that includes a detailed explanation of the project and an initial estimate of the costs and customer benefits associated with the project. Projects are then further developed including work scope identification and ranking based on customer-centric economic considerations and other important drivers such as safety requirements, environmental regulations, and outage timing opportunities. The planned outage schedule heavily influences capital project timing since many capital projects are implemented during longer duration planned outages to minimize implementation impact on plant availability. During these planned outages, inspections are completed on critical systems to ensure that the outage being executed addresses the work needed to sustain future unit reliability. These inspections can reveal unanticipated damage because many systems cannot be thoroughly inspected or evaluated until they are disassembled during an outage.

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Once capital project requests are fully developed, they are prioritized and presented for management review and approval. The review process focuses on ensuring that the projects utilize the best solution to address the issue at hand and represent the most cost-effective method for accomplishing the proposed work. Projects are approved if they are required to meet safety requirements and/or environmental compliance, are justified by an economic evaluation or represent normal/routine plant component replacements required for continued plant operations that are capitalized per authorized accounting policy.

In summary, the capital spending and approval process is designed to identify the optimal allocation of capital resources to meet safety requirements and environmental compliance while maintaining overall reliability performance and minimizing costs.

Q20. What do you mean by projects being justified by economic evaluation?

A20. The prioritization of economic projects is based on an internal rate of return (IRR) analysis performed comparing the costs of implementing the new project to its customer benefits. Included in the analysis are projected capital expenditures, future avoided outages, heat rate (efficiency), and fuel blending capabilities. Future avoided plant outage impacts include the value of avoiding events such as boiler tube failures, condenser or feedwater heater leaks, and turbine blade failures. The IRR of the project is based on the anticipated O&M, capital expenditures, and energy and capacity market value of the unit's operations with and without the project being implemented over its useful life.

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Q21. What would be the consequences of not completing the capital projects requested in the instant case?

A21. Failure to complete the approved capital projects described in this case could negatively affect plant reliability, environmental compliance, customer affordability, and/or safety.

Q22. Can you explain the governance process for approval of Energy Supply's capital projects?

A22. The capital governance process includes the documentation of project assumptions, calculation of costs and customer benefits, and a rigorous internal review. Projects costing less than $250,000 are approved by plant management, utilizing a project appropriation form, within a budget established based on historic plant expenditures. These projects generally do not require engineering and often reflect replacement-in-kind.

Projects that cost greater than $250,000 but less than $10 million and/or projects that require engineering are approved by the Energy Supply Capital Governance Board (CGB) which consists of plant directors, the Director of Engineering, and the Vice President of Energy Supply. A Project Approval Team (PAT) form is utilized to record CGB approvals.

Projects greater than $10 million require senior corporate executive approval, while projects greater than $50 million require approval by the Finance Committee of DTE Energy's Board of Directors. All projects greater than $10 million must be

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authorized by a Capital Appropriations Request Form (CARF) approved by the appropriate Company representatives.

ELG Rule Compliance

Q23. How does the EPA's Steam Electric ELG Rule affect the Company?

A23. As discussed in more detail by Company Witness Lee, the EPA's ELG Rule regulates how electric utilities must manage certain wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration Rule which revised some requirements from the 2015 ELG Rule and added time-based options for complying with the updated requirements for Bottom Ash Transport Water (BATW) and Flue Gas Desulfurization (FGD) wastewater. Subsequently, on May 30, 2023, the EPA published a Direct Final Rule which extended the deadline for units to opt-in to the cessation of coal compliance subcategory from the 2020 ELG Rule, which allows for operation of a unit until end of 2028 in lieu of installing a technology-based compliance option. Bottom ash transport water cannot be discharged to the environment after December 31, 2025, from a coal-fired power plant unless the plant committed to ceasing coal-fired operations by the end of 2028, by opting into the cessation of coal compliance subcategory. Regarding FGD wastewater streams, plants with FGD systems can comply with one set of limits by December 31, 2025 or comply with a set of more stringent limits by December 31, 2028 if the plant plans to continue coal-fired operations past 2028. Fly ash transport water (FATW) discharge limitations were not altered in the Reconsideration Rule and Direct Final Rule and continued to have a December 31, 2023 compliance date.

Q24. Did the Company submit any filings under the ELG Reconsideration Rule?

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A24. Yes. To utilize the ELG Reconsideration Rule's time-based options, companies were required to submit a Notice of Planned Participation (NOPP) to their state permitting agency. The Company filed NOPPs for Monroe and Belle River Power Plants. Please refer to additional testimony for Monroe and Belle River Power Plants below, as well as Company Witness Lee's testimony, for more information.

Q25. Has the Company made a formal commitment regarding how Belle River Power Plant will comply with ELG Rules?

A25. Yes. The NOPP that DTE Electric filed with the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on October 13, 2021 indicated a commitment to cease coal-fired operations at Belle River Power Plant. The fuel conversion at Belle River qualifies for ELG compliance as it results in ceasing coal-fired operations. This decision allows the Company to avoid installing new ELG-compliant bottom ash transport technology by the end of 2025.

Q26. How did the Company comply with the FATW-portion of the ELG Rule at Monroe Power Plant?

A26. The FATW-portion of the ELG Rule required companies to cease water discharges related to the transport of fly ash by the end of 2023. A project to install piping and silos and other infrastructure for the dry transport of fly ash from Monroe Power Plant boilers to a permitted storage area was completed in 2023, meeting the required compliance date.

Q27. How will the Company comply with the BATW-portion of the ELG Rule at Monroe Power Plant?

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A27. Monroe Units 1 and 2 are required to comply with the BATW-portion of the ELG Rule by the end of 2025. The Company plans to terminate the use of water for bottom ash transport on Monroe Units 1 and 2. In place of water conveyance, a dry drag chain conveyor system will be installed. This project was approved by the Company in 2022 and is fully underway and will meet the required compliance date.

Monroe Units 3 and 4 will not be required to terminate the use of water for bottom ash transport by the end of 2025. The Company submitted an NOPP for BATW on Monroe Units 3 and 4 and will comply with the BATW-portion of the ELG Rule by retiring Monroe Units 3 and 4 by the end of 2028, thereby eliminating their production of BATW and the need and expense to install a new transport system.

Q28. How does the Company plan to comply with the FGD wastewater-portion of the ELG Rule at Monroe Power Plant?

A28. Monroe Power Plant is required to comply with the FGD wastewater-portion of the ELG Rule by the end of 2025, unless the Company participates in the Voluntary Incentives Program (VIP) contained in the 2020 ELG Rule. The VIP allows compliance to be achieved by the end of 2028 if the Company agrees to meet more stringent FGD wastewater effluent limitations. The Company filed a VIP NOPP in October 2021, allowing it to evaluate alternative compliance technologies for Monroe Units 1 and 2.

The retirements of Monroe Units 3 and 4 in 2028 will eliminate the production of FGD wastewater on those units, thereby eliminating the need and expense to install

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FGD wastewater treatment systems on those units. Consequently, the Company filed a cessation of coal compliance subcategory NOPP in April 2023.

2022-2025 Capital Projects Summary

Q29. Can you provide a high-level discussion of the routine and non-routine capital expenditures being made by the Company for steam, hydraulic, and other power generation during the historical year 2022, the bridge period and the projected test period ending December 31, 2025?

A29. The Company's Energy Supply group makes routine ongoing expenditures across its existing generation fleet (steam, hydraulic, and other power generation) to maintain safe, environmentally compliant, reliable, and efficient operations. Most of these routine expenditures are primarily for Monroe and Belle River Power Plant projects. To a lesser degree, there are routine capital expenditures for the remaining assets including Blue Water Energy Center, Greenwood Energy Center, and peakers.

Non-routine capital project expenditures are driven by steam power generation unit upgrades with a heavy focus on environmentally mandated work at Monroe Power Plant. Other major non-routine capital projects included in the instant case are related to decommissioning and environmental remediation projects at retired coal plants, construction of Blue Water Energy Center, and new utility scale energy storage systems.

Q30. Can you explain Exhibit A-12, Schedule B5.1 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation" in more detail?

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A30. Exhibit A-12, Schedule B5.1 is a 9-page exhibit. Page 1 summarizes both "routine" and "non-routine" capital expenditures for 2022 (the historical actual test period) through the bridge period and the 12 months ending December 31, 2025 (the projected test period) for Steam Power Generation, Hydraulic Power Generation (Ludington Pumped Storage), and Other Power Generation. Page 2 provides additional detail for major non-routine capital expenditures for Steam, Hydraulic, and Other Power Generation. Page 3 summarizes routine Steam, Hydraulic, and Other Power Generation capital expenditures by plant site and major category. Pages 4 through 7 provide additional detail for the routine maintenance projects with expenditures of greater than $1 million for 2022 through December 31, 2025. Page 8 summarizes AFUDC included in the routine and non-routine capital expenditures. Finally, page 9 summarizes the plant in service and CWIP assumptions included in the capital forecast.

Q31. Can you provide additional details concerning Exhibit A-12, Schedule B5.1, page 1 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic, and Other Power Generation"?

A31. Yes. Line 2, Routine Steam Power Generation, includes capital expenditures necessary to operate and maintain Energy Supply's fossil steam power plant sites. Included are projects related to safety, boiler and turbine work, cables and controls, balance of plant projects and maintenance of environmental control systems. Safety expenditures include the capital projects necessary to maintain a safe work environment and meet applicable safety regulations and standards. Boiler and turbine work include the capital expenditures intended to maintain boiler or turbine operations, replace unreliable systems or equipment, support heat rate (efficiency),

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and/or address operating and maintenance problems related to the boiler and turbine systems. Examples of these projects include replacement of worn or damaged turbine blades, air heater baskets, and boiler tube sections such as waterwalls, reheaters, superheaters, and economizers. Cables and controls expenditures include the capital expenditures to replace or improve distributed control systems, large power cables, main unit transformers, and electrical switchgear. The balance of plant area expenditures includes the capital associated with mobile equipment, station air compressors, general service water systems, fuel handling equipment and systems, and plant vehicles and computers. Routine environmental expenditures include the capital necessary to maintain operations of existing environmental control and monitoring equipment. An example of routine environmental expenditures is the ongoing replacement of the Selective Catalytic Reduction (SCR) catalyst beds installed at Monroe Power Plant to comply with nitrogen oxides (NOx) emissions limits. These routine environmental capital expenditures associated with existing environmental systems differ from the non-routine environmental capital expenditures required to install any future new environmental systems.

Line 3, Non-Routine Steam Power, includes capital expenditures related to environmental compliance projects, site decommissioning, environmental remediation, and required equipment modifications related to retired power generation assets, as well as other plant level projects such as physical and cyber security at generation sites.

Line 6, Routine Hydraulic Power Generation, includes the Company's share of the routine capital expenditures necessary to operate and maintain the Ludington Pumped Storage facility.

Line 7, Non-Routine Hydraulic Production Plant, includes the Company's share of the capital expenditures related to the efficiency upgrade project at the Ludington Pumped Storage facility. This multi-year project included installation of new higher efficiency hydraulic turbines, main unit transformers, and upgraded generators on all six units.

Line 10, Routine Other Power Generation, includes capital expenditures related to maintaining peaker and combined cycle operations, including routine overhauls.

Line 11, Non-Routine Other Power Generation, primarily includes capital expenditures related to the development and construction of the Blue Water Energy Center (a 1,127 MW (summer-rated capacity) CCGT plant) and the development of new BESSs.

Lines 15 and 16 include Monroe regulatory asset routine and non-routine capital expenditures. Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193, the Company is including 2025 and all future Monroe capital expenditures in the regulatory asset.

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<u>Non-Routine Capital Expenditures</u>

Q32. Can you summarize Exhibit A-12, Schedule B5.1, page 2 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic, and Other Power Generation – Non-Routine"?

A32. Page 2 of Exhibit A-12, Schedule B5.1 provides project level detail for non-routine capital expenditures completed and planned for Steam Production, Hydraulic, and Other Power Generation from 2022 through December 31, 2025.

Q33. Can you explain line 2 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A33. Line 2 (Belle River Fuel Conversion) represents a project to convert the Belle River Power Plant's fuel source from coal to natural gas, consistent with the Company's approved 2022 IRP in Case No U-21193. The Order in Case No. U-21193 also included preapproval of the Belle River Fuel Conversion project.

In 2022, $1.4 million was spent on this project. The Company approved the funding and execution of this project in September 2022. An Owner's Engineer (OE) firm was contracted to provide engineering support, bid specification support, and technical review for the duration of the project. A request for proposal (RFP) to develop project scope, schematic design, and budgetary pricing was issued to support 2025 and 2026 gas conversions on Belle River Units 1 and 2, respectively.

For 2023, the project planned expenditures are $2.2 million and includes selection of an engineering, procurement, and construction (EPC) contractor for the fuel conversion of Belle River Units 1 and 2 that can meet the planned timelines. Work includes the development of an EPC bid specification that included the engineering

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design, material procurement, and installation of the natural gas systems for both units. Material procurement includes components for burner and ignitor modifications, ductwork modifications, air heater modifications, low and high-pressure gas reducing skids, a gas detection monitoring system, gas yard equipment, and components for associated electrical and controls upgrades. Additionally, a limited notice to proceed was issued in December 2023 to the selected EPC contractor.

In 2024, $39.3 million is projected to continue material procurement and complete detailed design, including erection arrangements and the controls upgrade requirements.

In 2025, $41.8 million is projected to be spent on this project. 2025 work scope includes installation of a natural gas pipeline from a nearby high-pressure interstate pipeline to the power plant, constructing the in-plant gas piping system, and controls systems for Belle River Unit 1, and retrofitting Belle River Unit 1 with natural gas burners in its fall periodic outage.

In 2026, which is beyond the projected test year in the instant case, the in-plant gas piping system and controls systems for Belle River Unit 2 will be constructed and the unit will be retrofitted with natural gas burners in its fall periodic outage.

Q34. Can you explain line 3 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A34. Line 3 (Belle River Bottom Ash Basin Modification (CCR)) represents a project to retrofit the north and south bottom ash basins at Belle River Power Plant with CCR

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Rule-compliant liner systems and to close the diversion basin by removal of all ash from the basin. The removed ash was transported to and disposed of at the Range Road Landfill. The Company spent $60 thousand in 2022 for project engineering. Project construction was initiated and was completed in 2023 for $3.4 million. This project was required by the EPA's CCR Rule as discussed in Witness Lee's testimony.

Q35. Can you explain line 4 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A35. Line 4 (Monroe Dry Fly Ash Conversion (ELG)) represents a project to convert the existing wet fly ash handling system at Monroe Power Plant to a dry system on all four Monroe Power Plant units. The EPA's fly ash ELG rule promulgated in 2015 required all liquid discharges to the environment from fly ash transport systems to cease by December 31, 2023. Conversion to a dry fly ash handling system required installation of new equipment to pneumatically transport ash from each generating unit's precipitator to new storage silos. The project included installation of transport piping from the unit precipitator hoppers to the local unit silos and installation of transport piping from the local unit silos to two central storage silos. Blowers were installed to convey the fly ash to the respective ash silos. The Company approved the funding and execution of this project in March 2020.

In 2022, $20.0 million was spent to engineer and construct a local ash silo for each of the four units, receive all long lead material, and complete the silos and interconnection piping systems for the four Monroe units. The equipment tie-in was completed on Monroe Unit 2 during an outage that ended in December 2022.

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In 2023, $20.8 million was spent to tie-in new fly ash handling systems on Monroe Units 1 and 3 in spring 2023 and Monroe Unit 4 in fall 2023.

In 2024, $1.2 million is projected for final site work, project demobilization, and performance testing. As required under the ELG Rule, the new fly ash handling systems were operational by the end of 2023.

Q36. Can you explain lines 5 and 47 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A36. Lines 5 and 47 (Monroe Bottom Ash Conversion (ELG)) represent a project to install an ELG-compliant bottom ash transport system that must be completed at Monroe Power Plant Units 1 and 2 by the December 31, 2025 EPA deadline. The Company approved the funding and full execution of this project in December 2022. The project scope includes removal of the wet bottom ash collection systems and major modifications to the boiler bottom hopper areas to permit installation of dry drag chain conveyor systems for ash removal. Project scope also includes the integration of the economizer ash handling systems into the dry fly ash handling systems utilizing dry flight conveyors. Once removed from the individual boilers, the bottom ash is moved outside the plant wall and into bunkers that function as the feed point for loading trucks with bottom ash to be sold or disposed of off-site.

The Company spent $4.2 million in 2022 to engineer ELG-compliant systems and procure long-lead materials.

For 2023, $11.4 million was projected to be spent to perform final engineering, bid project construction, and continue material procurement in support of the Unit 1

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and Unit 2 new bottom ash transport systems. In the Company's previous electric rate case, Case No. U-21297, the forecast had included the completion of engineering, bidding and award of project construction, and tie-in of new systems on Monroe Unit 3 and Unit 4 for converting the economizer ash transport systems. This work scope was not executed because the EPA ELG Direct Final Rule issued in May 2023 allowed Monroe Unit 3 and Unit 4 to retire by the end of 2028 without installing the new bottom ash handling systems otherwise required under the ELG Rule.

In 2024, $26.1 million is projected to award project construction and complete the installation of a common Unit 1-2 bunker and drag chain conveyor system. The new bottom ash handling system tie-in outage and connection to the new dry economizer ash transport system on Monroe Unit 2 will also be done in a fall 2024 outage.

In 2025, $23.1 million is projected to be spent for the new bottom ash handling systems that will be connected to Monroe Unit 1 in the fall of that year. Additionally, the new economizer ash transport system will be installed on Monroe Unit 1 in the fall. Included in this $23.1 million is $4.3 million of project costs that were prudently incurred prior to issuance of the May 30, 2023 EPA Direct Final Rule which extended the deadline for plants to opt-in to the 2028 early retirement provision promulgated in the 2020 ELG regulation. In the Company's previous electric rate case, Case No. U-21297, Staff Witness Kindschy acknowledged that the Company "may have incurred some capital expenditures in 2023 for this project prior to being able to opt-in to a 2028 retirement, and those capital expenditures can be included in the Company's next rate case for review and recovery."[1] The $4.3 million that was prudently incurred prior to issuance of the Direct Final Rule is included in line 5 of Exhibit A-12, Schedule B5.1, page 2 of 9 as a credit to the conversion project and is included in line 47 of Exhibit A-12, Schedule B5.1, page 2 of 9 for recovery through the regulatory asset. In accordance with the Company's 2022 IRP Order, recovery of Monroe Power Plant capital investments on this project made after January 1, 2025 will be processed through a regulatory asset, shown on line 47 of Exhibit A-12, Schedule B5.1, page 2 of 9.

As required under the ELG Rule, all the new dry bottom ash and economizer ash handling systems on Monroe Units 1 and 2 will be operational by the end of 2025. This work is required to maintain environmental compliance and allow the units to continue to provide power for customer benefit.

Q37. Can you explain lines 6 and 48 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A37. Lines 6 and 48 (Monroe FGD Wastewater (ELG)) represent a project to develop an ELG-compliant flue gas desulfurization (FGD) wastewater discharge treatment system at Monroe Power Plant. The Company spent $0.3 million in 2022 to perform technology evaluations and initial site engineering scoping efforts. In 2023, $0.5 million of expenditures were projected to evaluate compliance technologies for Monroe Units 1 and 2 and this evaluation will continue in 2024 and 2025 for $1.0 million each year. In accordance with the Company's 2022 IRP Order, recovery of Monroe Power Plant investments on this project made after

[1] Case No. U-21297 Kindschy, 7T 4512

January 1, 2025 will be processed through a regulatory asset, shown on line 48 of Exhibit A-12, Schedule B5.1, page 2 of 9.

Q38. Can you explain line 7 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A38. Line 7 (Monroe Dry Fly Ash Haul Road) represents a project that constructed a new asphalt road from Waters Edge Drive to the Monroe Power Plant vertical extension landfill. The Company spent $0.3 million to complete the new road in the first quarter of 2022. The new road reduces heavy truck traffic on public roads traversing residential areas and additionally minimizes related fugitive dust emissions.

Q39. Can you explain lines 8-13 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A39. Lines 8-13 (Site Security Projects and NERC Compliance Projects) represent projects required to improve power plant security. General site access security improvements as well as security enhancements for critical equipment are being implemented to mitigate security threats. In addition to physical security, North American Electric Reliability Corporation Critical Infrastructure Protection (NERC-CIP) compliance requires the Company to protect its cyber assets to minimize the risks to the electrical grid. The need for increased physical and cyber security for our electric assets are increasingly evident as seen in recent events at other utilities. NERC-CIP-003 was originally issued in 2010 and has undergone updates in 2014, 2016, and 2020 to include additional standards the Company needs to meet. NERC-CIP-003 requires the Company to control and track physical access to any NERC sensitive site. In order to be compliant with the CIP standard, the Company reviewed physical access at all power plants and developed projects to

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mitigate risks. Risks to the bulk electric system continue to increase. As a result, some project information, most noticeably site locations, must be tightly restricted to maintain the integrity of these measures. Project major work efforts, timelines, and expenditures are being provided as discussed below.

- Line 8 (Site Security Project 11504) represents a project to install a security station at a power plant site. The work includes modifying utilities, adding road lanes and signage, and installing security barriers and a security building. In 2022, $2.8 million was spent to complete engineering, procure long lead materials, and bid and award construction. For 2023, $2.2 million was projected to be spent to continue material procurement and initiate construction including relocation of transmission lines and Company primary utility lines from the power plant site to an adjacent right-of-way. In 2024, $5.4 million is the projected expenditures required to complete construction of project.
- Line 9 (Site Security Project 18700) represents a completed project that installed badge card readers at a power plant in January 2023. In 2022, $15 thousand was spent on door locks. In 2023, $52 thousand was spent on procuring badge readers and installation of the equipment to complete the project.
- Line 10 (Site Security Project 18906) represents a project to install a site entrance security building at a power plant. The Company spent $1 thousand in 2022 and planned to spend $0.8 million in 2023 for engineering, design, and procurement of the security building and to begin concrete foundation construction. The Company plans to spend $0.3 million in 2024

to complete the installation of the security building and tie-in of building utilities.

- Line 11 (Site Security Project 20061) represents a project to install a site security fence at a satellite property supporting power plant operations. Prior to the installation of the fence, there was no physical barrier to prevent trespassers from accessing the property. The Company spent $0.2 million in 2023 to complete this work.
- Line 12 (NERC Compliance Project 18885) represents a project to install a NERC-compliant perimeter fence at a power plant for expenditures of $0.6 million in 2022 and $1.1 million in 2023. The need for the new fence was triggered by the recent retirement and decommissioning of a power plant which was previously providing site security within its protected area.
- Line 13 (NERC Compliance Project 19895) represents a project that restored a NERC-compliant perimeter fence in 2023 for $7 thousand.

Q40. Can you explain lines 14-17 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A40. Lines 14-17 (Sibley Quarry Landfill Modification (CCR), Sibley Quarry Conveyor Installation (CCR), Sibley Quarry Infrastructure Modification (CCR), and Sibley Quarry Landfill Dewatering and Discharging Line) includes costs associated with site improvements required to allow safe and efficient acceptance of the significant quantities of coal combustion residuals (CCR) waste material that are being removed from Monroe Power Plant. Approximately 1 million cubic yards of bottom ash from the Monroe Power Plant inactive bottom ash basin is being transported to Sibley Quarry to meet the EPA's CCR regulation. The improved

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system will continue to be used after the completion of the Monroe Bottom Ash Basin Closure (CCR) project for continuing waste disposal activities.

- Line 14 (Sibley Quarry Landfill Modification (CCR)) – The Company spent $5.6 million in 2022 to install a drain piping shaft (chimney drain) and create a new landfill operation fill plan. In 2023, $1.8 million was spent to complete the project by installing a filtration system around the drain piping shaft and to relocate equipment to the current ash waste elevation. Approximately 23,000 cubic yards of material had to be moved so that stone could be placed for the chimney drain. Approximately 125,000 cubic yards of course aggregate limestone and approximately 40,000 cubic yards of crushed limestone was installed for the 18-ft diameter, 105-ft high chimney drain construction. The Company plans to spend $8 thousand in 2024 for final project closeout including final paperwork and as-built drawings. This project is required to allow continuing acceptance of bottom ash removed due to the closure of the Monroe bottom ash basin while continuing compliance with the provisions of Part 115, Solid Waste Management, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended, and its Solid Waste Disposal Area Operating License number 9602.
- Line 15 (Sibley Quarry Conveyor Installation (CCR)) – The Company spent $0.4 million in 2022 to complete engineering and installation of a new conveyor system that transports material from the designated truck unloading area to the bottom of the quarry.
- Line 16 (Sibley Quarry Infrastructure Modification (CCR)) – The Company spent $1.8 million in 2022 to engineer and construct a road, truck unloading

pad, and temporary office to support the increasing levels of activity the site will experience in support of the Monroe ash removal tasks supporting CCR and ELG requirements. The Company spent $9 thousand in 2023 for final project close out costs.

- Line 17 (Sibley Quarry Landfill Dewatering and Discharging Line) – The Company spent $1.8 million in 2022 to replace a portion of the piping that transports accumulated ground water out of the Sibley Quarry to the Detroit River in compliance with its National Pollutant Discharge Elimination System (NPDES) permit. The replaced portion of pipe is approximately 4,400 linear feet. The previous discharge piping was failing and required replacement. The Company spent $32 thousand in 2023 for project closeout.

Q41. Can you explain line 20 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A41. Line 20 (Monroe Bottom Ash Basin Closure (CCR)) represents a project to remove all bottom ash from the inactive bottom ash basin at Monroe Power Plant to meet the EPA's CCR regulation. This project includes the removal of approximately 1 million cubic yards, equal to over 1 million tons, of bottom ash from the Monroe inactive bottom ash basin and its transportation to Sibley Quarry. This project typically utilizes up to 10 trucks per day, each able to transport approximately 40 tons of bottom ash per load. Each truck averages five loads per day for the 46-mile roundtrip commute between Monroe Power Plant and Sibley Quarry. The trucks only operate from March to November because cold winter weather is not suitable for bottom ash material dewatering required for transport.

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The project received Company approval in December 2019. The final EPA CCR Rule requires closure to be initiated as soon as technically feasible, but no later than April 11, 2021 and be completed within five years. Closure was initiated on October 21, 2020.

In 2022, $15.4 million was spent to complete the transport of 0.6 million cubic yards of bottom ash from Monroe Power Plant that began in 2021.

For 2023, $14.6 million was projected to be spent to continue bottom ash material removal from the Monroe basin and its transportation to Sibley Quarry.

In 2024, $11.9 million is projected to be spent to complete the bottom ash removal and transportation. The closure of the Monroe bottom ash basin is expected in the summer of 2024. Company Witness Lee describes the Company's closure plans for multiple CCR sites in further detail in his direct testimony.

Q42. Can you explain lines 21 and 49 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A42. Lines 21 and 49 (Monroe Fly Ash Basin Closure (CCR)) represent a project required by federal and state regulations. The existing Monroe Power Plant fly ash basin will cease operations and be closed in place by dewatering the pond, grading the existing fly ash, and installing an impervious synthetic membrane cover. The existing fly ash basin utilizes a 400-acre pond with water depths up to 40 feet to contain approximately 25 million cubic yards of fly ash. The Company spent $0.5 million in 2022 to complete studies for conceptual compliance with the regulatory requirements and selection of the detailed engineering and design contractor.

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For 2023, $4.5 million was projected to be spent to begin engineering and design. During 2023, the engineering and design contractor initiated the dewatering system design and capping plan, existing site documents were updated, field sampling of soils was performed, site topography was surveyed, and a site grading plan was established. Significant work effort was required to prepare the large number of permits required by various municipalities, agencies, and authorities including U.S. EPA, Michigan EGLE, Monroe County Drain Commission, Monroe County Road Commission, and Monroe Township. The operating plan license agreement for the basin closure project was prepared and filed with Michigan EGLE in 2023.

In 2024, $5.0 million will be spent to continue engineering and design and develop a request for proposal to perform the basin closure. Engineering and design scope in 2024 will include fly ash basin dewatering and a water treatment system that complies with all applicable environmental limits. Additionally, the engineering and design contractor will develop an RFP to solicit bids from construction management firms for project execution. The RFP will be issued in the fourth quarter 2024.

In 2025, $25.0 million is projected to award the ash basin closure construction contract and begin project construction. In accordance with the Company's 2022 IRP Order, recovery of Monroe Power Plant investments for this project made after January 1, 2025 will be through a regulatory asset, shown on line 49 of Exhibit A-12, Schedule B5.1, page 2 of 9. This project is required by the EPA's CCR Rule as discussed in Witness Lee's testimony.

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Q43. Can you explain line 22 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A43. Line 22 (St. Clair Bottom Ash Basin Closure (CCR)) represents a project to clean and close the St. Clair bottom ash basins by removal of all the CCR material, decontamination, disposal, and basin backfill. The St. Clair bottom ash basins were subject to forced closure per the CCR Rule requiring them to cease receipt of waste and initiate closure as soon as technically feasible but by no later than April 11, 2021. As discussed in Witness Lee's testimony, the Company submitted a Part A Rule demonstration for the St. Clair bottom ash basins, requesting an alternative closure deadline based on cessation of coal-fired generation operations in spring of 2022, and a commitment to complete closure of the basins by October 17, 2023. The Company initiated closure on September 1, 2022 and withdrew the requested approval for a Part A Rule demonstration.

In 2022, $7.9 million was spent to complete the detailed engineering, analysis of soil borings, and elimination of source lines, followed by removal and transportation of bottom ash from the basins to Range Road Landfill and backfill the basins.

In 2023, $0.4 million was spent on final project closure costs, including final disposal of bottom ash, final backfilling, and issuance of a closure report. Basin closure was completed in the first quarter of 2023.

Q44. Can you explain lines 23-28 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A44. Lines 23-28 detail steam plant removal costs associated with the retirement and decommissioning of power generation assets at Harbor Beach, Conners Creek, River Rouge, St. Clair, and Trenton Channel Power Plants. Removal of retired steam generating units involves three primary activities, namely decommissioning, decontamination, and demolition. Decommissioning activities include the cost to isolate all unit systems and equipment to prepare them for removal from the site. This includes electrical, mechanical, plant controls, water and gas service shutdown, and electrical isolation from the transmission system. Decontamination includes disposing of hazardous materials (including draining oils, chemicals, and other fluids), cleaning tanks and pipelines, and removal of batteries and battery systems. Demolition includes asbestos and lead abatement, tearing down buildings, and removing and remediating the coal pile, ash basins, and ponds.

Q45. Can you explain line 23 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A45. Line 23 (Harbor Beach Decommissioning) is a project that finalized all site activities associated with the decommissioning and subsequent demolition of the Harbor Beach Power Plant. The Company spent $17 thousand in 2022 for monitoring the site developer's compliance to the sales contract terms.

Q46. Can you explain line 24 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A46. Line 24 (Conners Creek Seawall) was a project that restored the integrity of the seawall at the Conners Creek Power Plant site through installation of new sheet piling and associated shoreline repairs. The work was required to restore the integrity of the site waterfront to address rising water levels and the existing seawall's deteriorating condition that included separated tiebacks, undulating pilings, and corroded piles. Without this work the shoreline was at risk for sloughing into and impacting the Detroit River. The project was completed with

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an expenditure of $8.1 million in 2022 while fulfilling the permitting requirements of the US Army Corps of Engineers and Michigan EGLE.

Q47. Can you explain line 25 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A47. Line 25 (River Rouge Decommissioning) is a project to fully decommission and remove all plant structures including waste products from the site that has been in operation for approximately 70 years. In the instant case, capital expenditures for the River Rouge Power Plant decommissioning project support achieving a cold, dark, and dry status by the end of 2024. This terminology refers to a state in which the facility does not require heat or power, and all fluids have been removed from their respective tanks, reservoirs, and piping systems. Project approval was received from the Company in January 2023. The Company will address and request the remaining decommissioning expenditures beyond achieving a cold, dark, and dry state in a future rate case.

In 2022, $13.0 million was spent to complete work that began in 2021 involving environmental and site assessments. The Company also began plant electrical grid isolation, removed plant natural gas feeds, performed industrial cleaning that included removal of coal, oil, and chemicals from the site. The Company began work in 2022 towards achieving a cold, dark, and dry state for the plant. Additionally, plant utilities, such as city water and natural gas supply, have been separated from the power plant proper and site outbuildings.

In 2023, $21.1 million was spent to start asbestos abatement, environmental clean-up, equipment removal, and continue electrical isolation of the power plant and site

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outbuildings. Independence Demolition of Michigan was selected for initial work activities.

In 2024, $12.8 million is projected to be spent to complete electrical isolation of the power plant and outbuildings by end of second quarter of 2024 and establish a construction power feed for construction and various plant assets. Electrical isolation of the plant will complete the process of making the plant cold, dark, and dry.

Q48. Can you explain line 26 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A48. Line 26 (St. Clair Decommissioning) is a project to decommission St. Clair Power Plant, which was in operation for approximately 70 years. The St. Clair decommissioning was originally planned as a single project to achieve site demolition and final site grading. Due to the fact that coal handling equipment, boat unloading, firefighting, and control systems located on St. Clair property and within the St. Clair Power Plant proper must be kept in-service until Belle River Power Plant ceases coal-fired operations at the end of 2026, it was decided to perform the St. Clair demolition project in two phases. Full Company authorization for the first St. Clair decommissioning project to achieve cold, dark, and dry status by the end of 2024 was received on March 22, 2023. The project scope discussed below is associated with the first project. The Company will address and request the second project in a future rate case.

In 2022, $9.9 million was spent to sample for asbestos, lead, and PCBs, and to define site conditions. The Company also performed decontamination work,

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including the draining of oils, vacuuming of ash, washdown of boilers, and removal of chemicals, and started evaluating the work required to electrically separate the plant from the electrical grid. Engineering of systems to isolate plant water connections to the environment was also completed, while still maintaining operations of environmental systems, such as wastewater monitoring and oily waste treatment.

For 2023, $21.9 million was projected to be spent to continue work to achieve a cold and dry state in the plant and start asbestos abatement. Environmental clean-up and equipment removal in exterior outbuildings along with their demolition will be initiated. All basins will also be emptied, cleaned and filled in 2023.

In 2024, $13.0 million is projected to be spent to complete electrical isolation of the plant from the electrical grid and continue abatement and demolition of exterior outbuildings, namely structures associated with cooling water outfalls. Completion of the electrical isolation work will place the plant in a dark state, completing all cold, dark, and dry scope in the first project to decommission the St. Clair Power Plant.

Q49. Can you explain line 27 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A49. Line 27 (Trenton Channel Decommissioning) is a project to fully decommission and remove all plant structures including waste products from the Trenton Channel Power Plant site that has produced power for approximately 100 years.

In 2022, $10.0 million was spent to perform industrial cleaning, remove coal, oil, chemicals, lead, and asbestos, and initiate electrical isolation of the power plant. Additionally, the plant's natural gas feed was removed. All of these efforts were required to reach a cold, dark, and dry state for the plant. The Company also completed environmental and site assessments and developed a bid specification for site demolition and grading.

For 2023, $48.7 million was projected to be spent to continue decommissioning efforts. Work completed in 2023 included awarding of a demolition contract to Independence Demolition of Michigan, initiation of asbestos abatement and environmental clean-up. Equipment removal in plant outbuildings along with their demolition and the plant's electrical isolation was initiated. Electrical isolation of the plant was completed and the plant reached a cold, dark, and dry state. The project received full project approval by the Company in January 2023.

In 2024, $35.0 million is projected to be spent to continue asbestos abatement, removal of equipment inside the plant, and removal of stacks and the main turbine house through explosive demolition. Filling of all basins will be initiated along with the demolition of plant outbuildings in 2024. The stacks are scheduled to be demolished in March 2024 and the main turbine house will be demolished in May 2024. The Company will also begin final site grading and soil remediation activities.

In 2025, $6.9 million is projected to be spent to conclude soil remediation and complete final site grading. Performing these activities in the second quarter of 2025 will complete the decommissioning process.

Q50. Can you explain line 28 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A50. Line 28 (Trenton Channel Sea Wall) represents a project to restore the integrity of the seawall at the Trenton Channel Power Plant and the installation of a pedestrian greenway path along the Detroit River while meeting the permitting requirements of the US Army Corps of Engineers, Michigan EGLE, and the City of Trenton. The work includes removal of deteriorated sheet piles, maintenance of existing piles and installation of new piles along the Detroit River and Slocum Canal shorelines. Without this work, the shoreline was at risk for sloughing into and contaminating the Detroit River and Slocum Canal. Development of the pedestrian greenway path was stipulated in the approved demolition permit and will be installed along the Detroit River riverfront after the power plant is demolished and site grading is finalized.

In 2023, $0.4 million was spent to begin engineering and design of the seawall, natural shoreline, and greenway path.

In 2024, $1.0 million is projected to be spent to complete engineering and design of the seawall and begin engineering and design of the greenway path.

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In 2025, $9.5 million is projected to be spent to complete construction of the seawall for the riverfront and canal and complete engineering, design and construction of the greenway path by the end of 2025.

Q51. Can you explain line 32 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A51. Line 32 (Ludington Upgrades) represents an efficiency upgrade project at the Ludington Pumped Storage Facility that was being managed by Consumers Energy, Ludington's majority owner. The projected expenditures represent DTE Electric's 49 percent share of project costs. The upgrades of the six Ludington generating units began in 2013. Ludington Unit 3, the final unit upgraded, had its work completed for $10.0 million in 2022 and $1.5 million in 2023. Ludington Unit 3 returned to service on 2022, with a 34 MW increase of rated capacity now at 187 MW (DTE Electric's ownership percentage).

Q52. Can you explain line 35 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A52. Line 35 (Blue Water Energy Center (CCGT)) represents a project to build a 1,127 net MW (summer-rated capacity) CCGT generating plant on 40 acres of Company property adjacent to the existing Belle River Power Plant. This location was strategically selected due to its proximity to transmission lines and high-pressure natural gas pipeline infrastructure. The plant completed construction and became commercially operational in June of 2022. The unit generated 4,593 GWh during its first seven months of operation at an ROF less than 5% and a net heat rate of only 6,492 BTU/kWh.

On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE Electric's construction of this plant and authorized the Company to recover up to $951.8 million in costs for the plant through future rates.

In 2022, $11.8 million was spent to support plant startup, testing, and commissioning.

For 2023, the Company expected a net credit to the project in the amount of $4.5 million, primarily driven by a $1.4 million credit in March 2023 for a refund from ITC that came in higher than anticipated due to an interest rebate and a $3.2 million credit in June 2023 for a Canadian tax refund on natural gas purchased to support startup testing.

In 2024, $6.0 million is projected to be spent to complete punch list items and as-built drawings.

Final project costs are awaiting completion of final punch list items and as-built drawings in 2024. The Company currently projects total project costs of $946.5 million, which is below the $951.8 million approved by the Commission. This is an outstanding outcome, especially given the fact the project was constructed in the midst of the COVID-19 pandemic.

Q53. Can you explain line 36 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A53. Line 36 (BWEC Transmission Upgrades) represents transmission upgrades required for BWEC to acquire MISO generator interconnection rights. Since

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transmission network upgrades were excluded from the $951.8 million approved for the construction of BWEC in MPSC Case No. U-18419, this project is distinct from line 35 (Blue Water Energy Center (CCGT)).

In 2022, $5.5 million was booked for ITC transmission tower modifications. Due to the transmission line routing from the plant's electrical mat to the ITC substation, existing ITC transmission towers and their connecting transmission lines were raised to accommodate the installation of the dedicated BWEC transmission lines crossing under them.

In 2023, a refund of $4.8 million was credited back against the $9 million paid in 2021 for the Benton Harbor transformer project. This credit was received after new generating projects completed by other companies requested rights to and compensated the Company for utilizing part of the grid transmission capabilities previously funded by the Company through this project.

Q54. Can you explain line 37-39 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A54. Lines 37-39 (Blackstart Projects 1-3) represent projects that support the North American Electric Reliability Corporation (NERC) black start plan. Each region designates certain generating plants as black start units. A black start unit is one that can startup utilizing only its own internal power without support from the grid in the event of a major grid blackout, such as the 2003 blackout. This capability is critical to reestablishing grid integrity and restarting non-black start capable power plants following a grid blackout. In the Company's previous rate case, Case No. U-21297, ITC explained, "NERC requires each transmission operator to have a

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system restoration plan (SRP) and that a black start unit is an SRP" and that, "it is critical to the safety and reliance of the grid." [2] ITC further cautioned that black start resources are being lost through conventional generation retirements and that the Company's investments in the black start resources will ensure a resilient SRP. The black start unit project details disclosed are limited to maintain the integrity of these critical sites. ITC echoed this need for limited disclosure in the previous rate case, explaining, "the fact that some people outside the Company may have information regarding the black start resource projects (and [are] required to safeguard such information) does not vitiate the need for confidentiality and sensitive treatment of these projects."[3] The Commission was persuaded of the importance of these projects in maintaining grid security in their Final Order dated December 1, 2023[4], in Case No U-21297. Project major work efforts, timelines, and expenditures are discussed in detail below.

- Line 37 (Blackstart Project 10570 & 20255) represents a project that provides fuel and controls systems capabilities to enable a peaker site to startup without power from the grid. The project received Company approval in 2021.

  In 2022, $20.7 million was spent to complete design and initiate construction of fuel system modifications, develop, award, and initiate execution of mechanical erection contracts, and finalize the electrical erection specifications.

[2] December 1 order, page 42
[3] December 1 order, page 43
[4] December 1 order, page 43

For 2023, $10.4 million was projected to be spent to complete the fuel system modifications and testing and to install major electrical components.

In 2024, $2.2 million is projected to be spent to complete all construction activities, commission the installed equipment, and perform final project closeout activities including drawing updates.

- Line 38 (Blackstart Project 17611) represents a project that provides an existing site new equipment and controls that enable the peaker site to startup without power from the grid. The project received Company approval in June 2022.

  In 2022, $0.1 million was spent on project management activities.

  In 2023, $2.0 million was spent to bid and procure switchgears and two generators and to complete engineering efforts.

  In 2024, $6.1 million is projected to be spent to complete all construction activities and commission the installed equipment.

- Line 39 (Blackstart Project 18320) represents a project that provides an existing site equipment and controls that enable the peaker site to startup without power from the grid. The project received Company approval in January 2023.

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In 2022, $1.1 million was spent to initiate the project, bid and award engineering, and procure the diesel generators and automatic transfer switch.

For 2023, $4.0 million was projected to be spent to bid and award equipment installation, receive project materials, perform the equipment installation, and commission the installed equipment. This allows the unit to return to service until final long lead material is received in 2024.

In 2024, $0.4 million is projected to be spent to receive final long lead transfer switch, complete equipment installation, commission, and close out the project.

Q55. Can you explain line 40 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A55. Line 40 (Slocum Battery Pilot) represents a project to replace the diesel-fueled peakers at the Company's Slocum peaker site located in the City of Trenton with a 14 MW / 56 MWhr lithium-ion (Li-ion) BESS. The BESS will store excess energy that is generated on the grid during off-peak hours. This energy will then be available for dispatch during higher-priced peak hours.

In 2022, $7.6 million was spent for vendor selection and initial engineering work. These work activities included a bid specification and RFP for major equipment. Vendors for major equipment were selected and progress payments for long lead materials (i.e., batteries and transformer) were initiated. Those progress payments included two payments to the transformer supplier and one payment to the battery supplier. Delivery of all major equipment is scheduled to occur between the first quarter and third quarter of 2024.

In 2023, $10.1 million was spent to finish engineering, continue the procurement of materials, complete the construction bid package, and issue and award an RFP for construction. Additionally, the existing diesel peakers and their supporting equipment were decommissioned and removed from the site.

In 2024, $26.8 million is projected to be spent to support a 2024 installation and startup of BESS commercial operations in November 2024.

In 2025, $0.1 million is projected to be spent for final project closeout costs.

Q56. What is the Slocum Battery Pilot anticipated total project cost?

A56. The Slocum Battery Pilot project costs are projected to be $44.7 million. That amount has increased from prior projections primarily due to increases in lithium costs and actual construction bids received. Despite the cost increases, the Slocum battery pilot continues to provide the Company valuable insights and learnings on a small-scale project which will help the Company, contractors, and local municipalities succeed on the planned larger scale upcoming projects.

Q57. Can you explain line 41 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A57. Line 41 (Trenton Channel Energy Center BESS) represents expenditures associated with a 220 MW / 880 MWhr Li-ion BESS build, consistent with the build plan approved in the Company's 2022 IRP Order. The forecast includes the expenditures needed for engineering and long lead material procurement to support a 220 MW BESS starting commercial operations in 2026. The project received full internal Company approval in October 2023.

In 2023, $5.3 million was spent to bid and award equipment, and procure long lead materials (i.e., electrical breakers and transformer).

In 2024, $120.7 million is projected to be spent to take delivery of major electrical equipment and begin site preparation and construction in the fourth quarter of 2024. The Company executed contracts with the EPC contractor and battery vendor in January 2024, and these were submitted to the MPSC as noted below.

In 2025, $291.9 million is projected to be spent to take delivery of batteries and electrical collection equipment for the battery inverters and complete construction of the substation and BESS electrical switchyard.

As required in the Company's 2022 IRP Case No. U-21193, contracts totaling $334 million, which represents nearly 80% of the total projected spend for this project, were approved by the Commission in March 2024 in Case No. U-21566. The remaining 20% of project costs, totaling $89 million, include interconnection costs and permits ($23 million), BESS commodities and environmental remediation ($10 million), subgrade stabilization and fire suppression ($10 million), auxiliary transformer ($2 million), DTE labor ($3 million), owner's engineer and expert support costs ($6 million), project overheads ($16 million), and AFUDC ($19 million). The Company plans for the Trenton Channel Energy Center BESS to reach commercial operations in March 2026. Therefore, it is classified as construction work in progress (CWIP) through the projected period of this case. As explained by Witness Uzenski, projects in CWIP with an AFUDC offset do not impact the revenue requirement.

Q58. Can you explain line 42 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A58. Line 42 (Northeast 11-1 Decommissioning) represents a project to decommission the Northeast 11-1 peaker unit that retired in 2023.

For 2023, $0.3 million was projected to be spent to electrically disconnect the generator from the electrical grid, drain lube oil from the generator, and begin engineering of the decommissioning project. Engineering work will include environmental protections, isolation of fuel source, disabling of the fire protection system, and plant controls systems modifications.

In 2024, $0.3 million is projected to be spent to complete engineering of the decommissioning and execute the separation work needed on the peaker unit.

<u>Routine Capital Expenditures</u>

Q59. What information is provided on page 3 of Exhibit A-12, Schedule B5.1?

A59. Page 3 provides a summary of the routine capital expenditures for steam power, hydraulic power (Ludington), and other power generation facilities from the beginning of 2022 through December 31, 2025, broken down by site and by major spending category. Routine capital projects include projects to maintain plant reliability, maintain environmental compliance, provide safe operation of

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equipment, and improve efficiency, all with a focus on providing the customer affordable, low-cost generation. The Company has included all Monroe routine 2025 expenditures in a regulatory asset shown on Exhibit A-12, Schedule B5.1, page 3, line 13, consistent with the Commission's final Order in the Company's 2022 IRP filing, Case No. U-21193.

Reductions to Monroe Unit 3 and 4 Capital Expenditures and Updates to the Capital Projects Planned

Q60. What types of work do typical Monroe Power Plant major periodic outages include?

A60. Monroe units are brought offline once every four years for approximately three months to perform major periodic outages. During these outages, major maintenance is performed on the unit's systems, such as the boiler and steam turbines, to ensure future safe, reliable, efficient, and environmentally compliant operations.

Q61. As Monroe Units 3 and 4 approach retirement scheduled for the end of 2028, how has the Company modified its periodic outage capital expenditure plans?

A61. Prior to the Company's 2022 IRP in which the Company advanced the timing of the retirement of Monroe Units 3 and 4 from 2040 to 2028, the Company was anticipating investing over $200 million of capital expenditures during the Monroe Unit 3 2024 and Monroe Unit 4 2025 periodic outages to replace sections of boiler, replace turbine rotors and blades, and perform other maintenance critical for extended unit operation. Given the limited timeframes between the upcoming

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Monroe Unit 3 and 4 periodic outages and their pending retirements in 2028, the Company has scaled back or eliminated many capital projects previously planned to support operations until 2040. The planned scope reductions will lower routine large capital expenditures by approximately 50 percent, to just over $100 million for the Monroe Unit 3 and 4 periodic outages in 2024 and 2025. In addition to this reduction in Monroe Unit 3 and 4 routine capital project periodic outage expenditures, an additional $100 million of regulatory-mandated non-routine ELG-related investments for these units is no longer required and customers have been saved the expenditures.

Q62. Has the Company discussed changes in capital projects on Monroe Units 3 and 4 under a 2028 retirement in a previous filing?

A62. Yes. In the Company's 2023 electric rate case, MPSC Case No. U-21297, the Company delineated the avoidable and unavoidable capital expenditures that would be possible if Monroe Units 3 and 4 were to retire in 2028. Since that filing, further information has come to light that has resulted in updates to the scope and costs of the unavoidable capital investment requirements for the upcoming Monroe Unit 3 and 4 periodic outages.

Q63. What routine capital project scope planned for the Monroe Unit 3 periodic outage in 2024 required updating since the last rate case, Case No. U-21297?

A63. Since the initial filing of the last rate case, nine projects have been cancelled on Monroe Unit 3 with seven other projects being executed as previously planned. Recent unit equipment inspections and failures have also triggered the Company to move forward with two capital projects not previously anticipated to be required under a 2028 retirement. These projects now deemed as required at this time include the Air Heater Cold-End Basket Replacement Project and the Horizontal Reheat Tube Replacement Project. Additionally, the Company has determined that the turbine valve project should fully overhaul all eight governor valves based on age and condition of internal parts and four throttle valves due to valve seats cracking and weld failures. The original turbine valve project anticipated requiring only limited inspections and repairs of some of the valves which previously made that portion of the work an O&M expense instead of a capital asset replacement. Finally, the Company has reduced the Unit 3 DCS project by approximately 40 percent to focus on only completing work scope critical for continued unit operations until retirement of the unit at the end of 2028. I elaborate on these project justifications and further explain these updates below.

Q64. What is the current condition of the Monroe Unit 3 air heater cold-end baskets?

A64. The Monroe Unit 3 air heater cold-end baskets were installed in 2015 and have a typical life expectancy of 7-10 years. The existing baskets are failing due to material loss caused by normal operational corrosion. Recent inspections show 30 percent of the basket material has been lost. If the air heater baskets are not replaced, continued material loss will cause air heater imbalances requiring unit outages to clean and balance the air heater, while risking likely drive gear failures. A gear drive failure will cause the unit to be in a multi-week forced outage until repairs to the air heater(s) are completed. The plant has already experienced two air heater failures in recent years on Monroe Unit 2, in which elements fell out and jammed the air heater drive resulting in multi-week forced outages. Additionally,

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not performing the project would increase the heat rate of future operations. Furthermore, the discounted payback for the project was calculated to be 2.2 years, well within the projected operating life of the unit. Alternatively, if this project was not completed, in addition to the costs associated with cleaning and balancing the air heaters, the forecasted costs to customers from each air heater failure event between 2024 and 2028 would be $0.5 million in repair costs and over $3 million in purchase power expense during a 2-week forced outage repair.

Q65. What is the current condition of the Monroe Unit 3 horizontal reheater?

A65. The Monroe Unit 3 horizontal reheater is original to the unit and is failing due to oxygen pitting corrosion and fly ash erosion. Since Monroe Unit 3's last periodic outage in 2019, the unit experienced nineteen horizontal reheater tube leaks, forcing the unit offline for multiple weeks to perform repairs. During inspection of the failed reheater tubes, oxygen pitting damage was found. The Company plans to replace 4,000 linear feet of tubes in the most heavily damaged areas to minimize future horizontal reheater tube leaks until the unit's 2028 retirement. Without the project, the Company anticipates at least one additional tube leak outage requiring extensive repairs each year. Reheater repairs are difficult and often lengthy because tight tube spacing can necessitate cutting away undamaged tubes to gain access to complete required repairs and then restoring those removed tubes to complete the repair effort. Additionally, such tube failures often cause collateral damage to surrounding tubes. The discounted payback for the project was calculated to be 1.8 years, well within the projected operating life of the unit. Alternatively, if this project was not completed, the forecasted costs to customers from each horizontal reheater tube leak event between 2024 and 2028 would be $0.5 million in repair

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costs and over $3 million in purchase power expense during a 2-week forced outage repair.

Q66. What scope was added to the Monroe Unit 3 Turbine Valves project in the 2024 periodic outage since the last rate case, Case No. U-21297?

A66. In 2023, further analysis of turbine valve scope was completed, leading to updated repair plans for the governor valves and throttle valves.

That further analysis included a review of age and condition of internal valve components which indicated that the eight governor valves needed to have their stems, bushing, and seats replaced. This scope of work will ensure proper operation of this critical safety system that is required for turbine control and safe shutdown.

Additionally, the Company plans to overhaul all four Monroe Unit 3 throttle valves due to the valve seat failures observed in 2022 at Belle River Power Plant. Over many years of normal operations at high temperatures (1000ºF), valve seats containing stellite alloys become brittle, crack, and fail, causing damage to downstream turbine blades. Thus, the Company plans to proactively replace the throttle valve seats before turbine damage occurs.

Without routine overhaul of these valves, there is risk of the valves not functioning properly, leading to damage to the unit's turbines or an overspeed condition resulting in catastrophic turbine failure. Accordingly, this project is classified as a safety project.

Q67. What is the status of the Monroe Unit 3 DCS and Control Room upgrade project?

A67. The Monroe Unit 3 DCS and Control Room project cost has been reduced from $5.0 million to $3.1 million. In the Company's 2023 main electric rate case, Case No. U-21297, the costs for this project were excluded from the approved revenue requirement because the Company was reviewing the need for the upgrades and the necessity for the project was less certain. During 2023, the Company reduced the project scope to one that is solely focused on critical work necessary to support continued operations. Scope removed from the project included demolition of original alarm panels, integration of a display that monitors and controls electrical control positions throughout the unit, and furniture replacements. Without at a minimum performing this scaled-down project, the Company expects chronic controls component failures to cause derates and outages equivalent to multiple outage days per year. The discounted payback for the project was calculated to be 2.2 years, well within the projected operating life of the unit. Additionally, the project maintains consistency in the control systems design and function across all four units at Monroe. This continuity of design and function is critical to avoid human performance errors as operators routinely move from unit to unit.

Q68. Besides scope updates to Monroe Unit 3 periodic outage projects, what additional updates has the Company included in the filing of the instant rate case?

A68. The Company has updated cost projections based on the latest information available. For two projects, the Monroe Unit 3 Coal Mill Classifiers project and the Monroe Unit 3 Waterwall Tubes project, costs to complete the projects are

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forecasted to be approximately $1 million more for each individual project than the scaled down costs estimated in Case No. U-21297.

Q69. Why did Monroe Unit 3 Coal Mill Classifier project cost projections increase since Case No. U-21297?

A69. In Case No. U-21297, the Company inadvertently presented only contractor labor costs as unavoidable costs related to the scaled down version of the Unit 3 Coal Mill Classifier project and did not include materials and overheads to perform the scaled down version of the project. Accordingly, project costs in the instant case now include $0.6 million for materials and $0.7 million of overheads (indirect and shared costs). The scope remains consistent with the scaled down version of the project described in Case No. U-21297 and includes replacement of the upper and lower bearings based on OEM recommendations, as opposed to the previously planned full classifier overhaul project that was projected to exceed $5 million. Alternatively, if the bearings are not replaced, each bearing that fails will require the respective coal mill to be forced offline for emergent repair and result in a derated capacity for the unit. The discounted payback for the project was calculated to be 2.0 years, well within the projected operating life of the unit.

Q70. Why did Monroe Unit 3 Waterwall Tubes project cost projections increase since Case No. U-21297?

A70. In 2023, the Company procured the waterwall materials and evaluated installation labor bids for the Monroe Unit 3 Waterwall Tubes project. While the Commission excluded 50 percent of the project costs from rate base in Case No. U-21297 based on MPSC Staff's assumptions that costs would reduce 50 percent if the square

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footage being replaced was reduced by 50 percent, the actual bids received did not provide the 50 percent reduction assumed by the MPSC Staff. The cost projection for the revised project now totals $13.6 million, consisting of $8.8 million for installation labor, $1.1 million for scaffolding, $0.5 million for materials, $0.7 million in shared costs, $0.4 million for inspections, $0.3 million in other contract labor (including abatement, air monitoring, engineering, electrical, and industrial cleaning), $0.3 million in DTE Electric labor, and $1.5 million for overheads. The scope in the instant case remains consistent with the scaled down version of the project described in Case No. U-21297 and includes replacement of 2,000 square feet of waterwall panels, as opposed to a full, 4,000 square foot replacement project that was projected to cost $19 million. Based on tube thickness measurements and tube wastage trends, in addition to data from other failure modes, Monroe Unit 3's boiler will experience multiple tube leak forced outages annually if the scaled back waterwall replacement project is not completed. The costs to customers from each waterwall tube leak event between 2024 and 2028 is approximately $0.4 million in repair costs and $1-2 million in purchase power expense during each 1-week forced outage repair. The discounted payback for the project was calculated to be 2.7 years, well within the projected operating life of the unit.

Q71. What projects had their scope updated since the last case, Case No. U-21297, for the Monroe Unit 4 periodic outage in 2025?

A71. In 2023, the Company further reviewed and reduced the Unit 4 DCS Project scope to minimize scope to only that scope of work critical for continued operation to retirement. Additionally, the need for a reasonable amount of preventative maintenance continues to be validated. For example, the Monroe Unit 4 south

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boiler feed pump condenser project was originally scheduled to be completed in 2025 but required execution in 2023 on an emergency basis.

Q72. What is the status of the Monroe Unit 4 DCS and Control Room project?

A72. Consistent with the prior discussion involving the Monroe Unit 3 DCS and Control Room project above (Q/A 67), the Monroe Unit 4 DCS and Control Room project has been reduced to $2.6 million which is the amount necessary to support continued operation and address major reliability risks associated with obsolete equipment which is no longer supported by vendors. Without performing this scaled-down project, the Company expects chronic controls component failures resulting in derates and outages equaling multiple outage days per year. The discounted payback for the project was calculated to be 2.5 years, well within the projected operating life of the unit. Additionally, the project maintains consistency in the control systems design and function amongst all four units at Monroe. This continuity of design and function is critical to mitigating the risk of human performance errors for the operators running the units.

Q73. Why did the Monroe Unit 4 south boiler feed pump turbine (SBFPT) condenser require retubing in 2023?

A73. The south boiler feed pump turbine condenser required retubing in 2023 because in February of 2023 a large number of condenser tubes developed leaks in this equipment which was original to Monroe Unit 4. Over time, the condenser required 39 percent of its cooling water tubes to be plugged to stop leaks caused by ammonia grooving, erosion, and stress corrosion cracking. After tubes are plugged, water velocities through the remaining tubes increase causing additional wear. The old condenser was not capable of providing the heat transfer required to operate the boiler feed pump turbine at full capacity without causing turbine blade damage due to increased back-pressure. Without the condenser in-service, the unit is limited to half load operations. The discounted payback for the project was calculated to be 1.5 years, well within the projected operating life of the unit.

Routine Capital Expenditures - Steam Power Generation

Q74. What were the Company's routine capital expenditures completed in 2022 for Steam Power Generation?

A74. During 2022, the Company's Energy Supply group routine capital expenditures related to Steam Power Generation were $219.0 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 7, column (b). These expenditures included the following projects that individually exceeded $1 million as detailed on page 4 of Exhibit A-12, Schedule B5.1:

- The Belle River Unit 1 low pressure (LP) turbine rotors and blades were replaced for $5.4 million (Exhibit A-12, Schedule B5.1, page 4, line 1). Inspections had identified blade erosion and rotor cracking that needed to be addressed to ensure continued safe and reliable operation of the LP turbines.
- The Belle River Unit 1 turbine valve actuators were replaced for $4.0 million (Exhibit A-12, Schedule B5.1, page 4, line 2). The original actuators provided by the OEM have been replaced across the industry due to maintenance issues, lack of spare parts, and an absence of qualified companies capable of repairing them. The replacements were required to ensure the continued reliable operation of this system that controls turbine

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loading. Failure of these valves to properly operate would impact the ability to properly control unit output.

- Waterwall tubes were replaced on Belle River Unit 1 for $3.8 million (Exhibit A-12, Schedule B5.1, page 4, line 3). The project replaced 2,100 square feet of boiler waterwall panels damaged by the ordinary wear and tear of quench cracking and soot blower erosion to support continued reliable boiler operation.
- Belle River Unit 1 high pressure (HP) turbine blades were replaced for $3.4 million (Exhibit A-12, Schedule B5.1, page 4, line 4). During disassembly of the HP turbine stop valves at the start of the 2022 periodic outage, it was discovered that stop valve disk wear-resistant stellite coatings had failed and likely entered the HP turbine. During the previous 2016 periodic outage, the valves were inspected and had shown no indications of dis-bonding failures. Further turbine inspections revealed that 11 rows of rotating and stationary blades of the HP Turbine were suffering from foreign object damage and needed to be replaced. By addressing the damage during this periodic outage, the Company was able to potentially avoid a future significant forced outage likely in excess of 90 days to complete the repair.
- Underground electrical cables (each approximately 1-mile long) from Belle River Unit 1 to the condenser cooling water intake structure located on the St. Clair River were replaced for $2.8 million (Exhibit A-12, Schedule B5.1, page 4, line 5). The intake structure equipment provides water from the river to the plant. Testing of the power feed cables following recent failures had indicated degradation of the cables, necessitating replacement to ensure continued safe and reliable operation.

- The Belle River Unit 1 boiler ignitor system was replaced for $2.2 million (Exhibit A-12, Schedule B5.1, page 4, line 6). The ignitor system was replaced to address the operational issues that have developed into safety concerns for the operators working the burner decks. The ignitors on Unit 1 are original equipment and have been in service since 1984. The performance of the ignitor components has degraded, frequently failing to insert when required, which then requires the operator to manually position these components. This puts the operator at risk to mechanical and electrical hazards.
- The Belle River Unit 1 HP turbine valves were rebuilt for $2.1 million (Exhibit A-12, Schedule B5.1, page 4, line 7) as part of the normal scheduled work on these valves to ensure continued proper operations. The stellite coatings on the valve seat disks were found to be delaminated, releasing foreign material into the turbine requiring extensive HP turbine blade repairs, as discussed above. The HP turbine stop valves and control valves must operate properly to provide overspeed protection for the turbine and prevent possible catastrophic failure.
- Belle River Unit 1 primary air heater baskets were replaced for $2.0 million (Exhibit A-12, Schedule B5.1, page 4, line 8). As air heater baskets deteriorate with age, the basket plates become loose and can drop into the moving ductwork and prevent the air heater from rotating. Without a properly functioning air heater, the unit cannot operate. Additionally, the basket replacements improve boiler efficiency.
- A portion of the horizontal middle reheater on Belle River Unit 1 was replaced for $1.4 million (Exhibit A-12, Schedule B5.1, page 4, line 9). The

horizontal reheater is located within the downdraft section of the boiler. These tubes were replaced due to preferential corrosion of original construction shop welds that were compromised by acidic corrosion taking place during boiler washes that remove ash and slag accumulations associated with utilization of low sulfur western fuel at the plant. These tubes required replacement to avoid tube failure outages.

- Belle River Unit 1 generator phase bushings were replaced for $1.2 million (Exhibit A-12, Schedule B5.1, page 4, line 10). In early 2020, the plant discovered that the Z-phase generator bushing (insulator) seal had failed and was leaking hydrogen. Inspection of the remaining five (5) generator bushings identified signs of deterioration requiring replacement to prevent a failure that would release hydrogen into the plant and force a unit outage.
- $1.1 million was spent to rebuild the purple coal mill on Belle River Unit 1 due to service hours and lube oil analysis indications of deteriorating internal components (Exhibit A-12, Schedule B5.1, page 4, line 11). Due to the abrasiveness of coal, coal mill parts experience significant wear in the process of converting lump coal to a fine powder consistency suitable for boiler combustion and need to be disassembled, repaired, and components replaced approximately every 10 years. Purple coal mill was last overhauled in 2012 and was due for this work.
- Two (2) induced draft (ID) fan motors on Belle River Unit 1 were replaced for $1.0 million (Exhibit A-12, Schedule B5.1, page 4, line 12). These motors require overhaul/replacement approximately every 10 years and the motors were due for this work.

- In preparation for the Belle River Unit 2 planned outage in 2024, $2.9 million was spent to engineer and procure replacement LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 4, line 13). Inspections identified blade erosion and rotor cracking that needed to be addressed to ensure continued safe and reliable operation of the LP turbines.
- The Belle River fuel supply east main coal pile project was completed for $2.3 million (Exhibit A-12, Schedule B5.1, page 4, line 14). The east main coal pile was used to fuel both St. Clair Power Plant and Belle River Power Plant. When St. Clair Power Plant retired in 2022, the existing equipment required modification to eliminate the risk of safety hazards (fires) due to combustible dust and coal accumulation stranded in the equipment no longer in operation. This modification required the removal of non-operational diverter gates and chutes, removal of dust collector ductwork and installation of new ductwork, installing a new metal (tramp iron) detection system, removal of two abandoned coal bins and four slide gates, installation of a new transfer chute, new instrumentation, and a new dust suppression system. Isolating the abandoned St. Clair Power Plant conveyor systems through installation of barriers was required to prevent coal and combustible dust from entering the retired St. Clair Power Plant fuel system where it would create a risk of fire or explosion.
- $1.8 million was spent to replace the Belle River fuel supply DCS consoles (Exhibit A-12, Schedule B5.1, page 4, line 15). The previous system was obsolete and required an upgrade to ensure reliable communication and eliminate compatibility issues with the Belle River Power Plant DCS.

Additionally, this ten-year-old equipment was no longer supported by the vendor.

- Belle River 3TH-8 fuel supply dust collector was replaced for $1.7 million (Exhibit A-12, Schedule B5.1, page 4, line 16). The dust collector in the fuel supply system collects dust that is inherent to the transportation of coal via conveyor belts. The dust is collected from multiple points along the fueling system via several large ducts that are under vacuum. The dust collector filters the dust laden air, allowing the clean air to exhaust back to the atmosphere, while the coal dust is transported by screw conveyors back to the conveyor belts. The replacement mitigates combustible dust and complies with the National Fire Protection Association (NFPA) combustible dust guidelines.
- $1.7 million was spent to begin separation of St. Clair Power Plant from the Fuel Supply system (Exhibit A-12, Schedule B5.1, page 4, line 17). There are a number of systems in the St. Clair Fuel Supply system that are interrelated with the Belle River Power Plant as all coal deliveries to Belle River are unloaded at and pass through the St. Clair Power Plant fuel supply system. Although St. Clair Power Plant retired in 2022, these interrelated systems must remain functional to continue fueling the Belle River Power Plant until its ultimate conversion to operation on natural gas. The project scope was to completely separate St. Clair Power Plant from the Fuel Supply System that will continue to be operated in support of Belle River Power Plant. The scope of the separation effort included fire protection, general service water, wastewater, stormwater, low voltage electrical, and medium voltage electrical switchgear systems.

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- The Belle River fuel supply CV2 to CV4 transfer chute was replaced for $1.3 million (Exhibit A-12, Schedule B5.1, page 4, line 18). This chute was replaced to prevent combustible coal and dust accumulation that would become a safety hazard.
- In preparation of the Greenwood Unit 1 outage in 2025, $7.6 million was spent on engineering and initial material procurement efforts for LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 4, line 19). Stress corrosion cracking of multiple blade root connections needs to be addressed to ensure continued safe and reliable operation of the LP turbines.
- The Greenwood Unit 1 north induced draft (ID) fan was overhauled for $1.0 million (Exhibit A-12, Schedule B5.1, page 4, line 20). Inspections conducted following an instance of abnormal vibration levels revealed bearing wear beyond the operational tolerance specifications and hydraulic fluid leaks. The increasing vibration needed to be addressed to ensure continued reliable operations.
- In preparation for the Monroe Unit 1 2023 periodic outage, $9.6 million was spent to procure material for fabrication of new LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 4, line 21). Inspections were conducted and revealed the expected ordinary wear and tear on the L-0 through L-5 blade rows. This project also addressed stress corrosion cracking concerns on the original LP turbine forgings which are an industry-wide safety concern. Additionally, SCR catalyst modules for layers 1, 2, and 4 were purchased for $4.0 million (Exhibit A-12, Schedule B5.1, page 4, line 22). The catalyst module replacements were required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines. $3.9

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million was spent to begin initiation of the purchase of 4,000 square feet of waterwall tubes (Exhibit A-12, Schedule B5.1, page 4, line 23). The boiler tubes deteriorate due to combined effect of corrosion fatigue, fireside corrosion, creep damage, and tube thinning. Thirty-seven (37) expansion joints were purchased for $2.7 million (Exhibit A-12, Schedule B5.1, page 4, line 24). The replacements were based on near term failure risk which would affect unit reliability, efficiency, and result in a safety risk to plant personnel. $2.4 million was spent to procure replacement materials for the south air heater hot and cold end baskets (Exhibit A-12, Schedule B5.1, page 4, line 25). The previous baskets had degraded due to corrosion and, if not addressed, would become loose, cause an imbalance and lead to a drivetrain failure. The replacements restored physical integrity and heat transfer efficiency of the air heater. $1.6 million was spent to procure 10,000 linear feet of tubing for replacement of reheat outlet pendants (Exhibit A-12, Schedule B5.1, page 4, line 26). The tubes were prone to stress-induced precipitation hardening failures and required replacement to ensure reliable operation. $1.6 million was spent to engineer and procure materials for rebuilding the Unit 1 north and south FGD booster fans (Exhibit A-12, Schedule B5.1, page 4, line 27). Due to the corrosive environment in which these fans operate, the fans require repair or replacement of the hub and blades every eight (8) years to avoid component failures and damage to fan internals. This maintenance was due. Engineering and material procurement continued for $1.1 million for a 1.5 MW backup generator to be installed in 2023 on the Monroe Unit 1 FGD (Monroe Unit 1 FGD Asset Preservation) (Exhibit A-12, Schedule B5.1, page 4, line 28). The backup

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generator provides emergency power to allow stabilization of critical FGD equipment during power failures. This backup generator provides dedicated emergency power to the FGD equipment. This project is also detailed in a new report (Exhibit A-12, Schedule B5.1.1) as requested in the Commission Order in Case No. U-21297. The report demonstrates the reasonableness and prudence of the FGD Asset Preservation projects, including the fact that the costs of installing FGD back-up generators now are the same as installing the generators during initial FGD construction 15 years ago, the risks of damage associated with not having back-up generators during a loss of power, and the potential future uses of the generators after the Monroe units retire. Finally, $1.1 million was spent to start engineering and procurement of materials to replace the existing Monroe Unit 1 coal mill primary air duct and damper (Exhibit A-12, Schedule B5.1, page 4, line 29). The previous ductwork had thinned, allowing fugitive dust leaks, creating fire and other safety risks.

- 4,000 square feet of Monroe Unit 2 waterwall tubes were replaced for $16.8 million (Exhibit A-12, Schedule B5.1, page 4, line 30). The boiler tubes had deteriorated due to the combined effects of corrosion fatigue, fireside corrosion, creep damage, and tube thinning. Boiler tubes sections were replaced with material that incorporates an Inconel weld overlay protective coating that is resistant to the harsh reducing atmosphere boiler combustion zone conditions. Inconel protective coatings have been utilized for over 10 years and have proven extremely well-suited for this application.

- IP turbine blades were replaced on Monroe Unit 2 for $4.3 million to eliminate erosion damage on the previous blades (Exhibit A-12, Schedule B5.1, page 5, line 31).
- Monroe Unit 2 SCR catalyst modules for layers 1, 2, and 4 were replaced for $4.1 million (Exhibit A-12, Schedule B5.1, page 4, line 32). The catalyst module replacements were required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- Monroe Unit 2 coal mill primary air (PA) duct and dampers were replaced for $3.6 million (Exhibit A-12, Schedule B5.1, page 4, line 33). The previous ductwork had thinned, resulting in fugitive dust leaks.
- Twenty (20) expansion joints were replaced on Monroe Unit 2 for $2.7 million (Exhibit A-12, Schedule B5.1, page 54, line 34). The replacements were required to maintain unit reliability and efficiency, while also mitigating safety risks to plant personnel.
- Monroe Unit 2 horizontal reheater tubes (960 linear feet) were replaced for $2.6 million (Exhibit A-12, Schedule B5.1, page 54, line 35). The horizontal reheater is located within the downdraft section of the boiler. These tubes required replacement to avoid tube failure outages. Tube failures occur from oxygen pitting corrosion, fly ash erosion, abrasive wear of closely spaced horizontal reheater and primary superheater tubes, and the use of soot blowers which operate to remove and prevent ash build-up.
- $1.9 million was spent to replace the Unit 2 FGD absorber inlet expansion joint and flanges on both upstream and downstream sides of the joint (Exhibit A-12, Schedule B5.1, page 54, line 36). Flue gas and moisture

cause progressive deterioration to the inlet expansion joint necessitating periodic replacement to prevent forced outage failures.

- The Monroe Unit 2 north and south FGD booster fans were rebuilt for $1.5 million (Exhibit A-12, Schedule B5.1, page 4, line 37). Due to the corrosive environment in which these fans operate, the fans require repair or replacement of the hub and blades every 8 years to avoid risk of a component failure and damage to other fan internals. This maintenance was due.
- $1.3 million was spent to complete Monroe Unit 2 DCS and control room modifications (Exhibit A-12, Schedule B5.1, page 4, line 38). The equipment and software were at risk from a reliability perspective, requiring modifications to keep the plant's control systems reliable. The DCS hardware was last replaced over a decade ago and the associated software dates back to the 1980's. Additionally, the equipment was no longer supported by the vendor.
- Monroe Unit 2 coal mill silo 2-1 (Exhibit A-12, Schedule B5.1, page 4, line 41) and silo 2-7 (Exhibit A-12, Schedule B5.1, page 4, line 39) were rebuilt for $1.2 million each. Monroe Unit 3 coal mill silo 3-5 (Exhibit A-12, Schedule B5.1, page 4, line 45) and silo 3-6 (Exhibit A-12, Schedule B5.1, page 4, line 46) were rebuilt for $1.2 million and $1.1 million, respectively. The chemical and abrasive properties of coal within the silos resulted in corrosion and erosion of the silo walls and compromised the structural integrity requiring repairs.
- $1.2 million was spent for engineering, material procurement, and preliminary installation work for a 1.5 MW backup generator to be completed in 2023 on Monroe Unit 2 FGD (Monroe Unit 2 FGD Asset

Preservation) (Exhibit A-12, Schedule B5.1, page 4, line 40). The backup generator will provide emergency power to allow for stabilization of critical FGD equipment in the event of a power failure. This project is also detailed in a new report (Exhibit A-12, Schedule B5.1.1) as requested in the Commission order in Case No. U-21297. The report demonstrates the reasonableness and prudence of the FGD Asset Preservation projects, including the fact that the costs of installing FGD back-up generators now are the same as installing the generators during initial FGD construction 15 years ago, the risks of damage associated with not having back-up generators during a loss of power, and the potential future uses of the generators after Monroe units retire.

- Monroe Unit 2 FGD mist eliminators (1st and 2nd stages) were replaced for $1.0 million (Exhibit A-12, Schedule B5.1, page 4, line 42). The original mist eliminator trays were plugged, damaged, and worn. They were replaced to improve FGD moisture removal and emission monitoring equipment reliability and accuracy.
- SCR catalyst modules for layer 1 on Monroe Unit 3 were replaced for $3.2 million (Exhibit A-12, Schedule B5.1, page 4, line 43). The catalyst module replacements were required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- $1.6 million was spent to replace the Monroe Unit 3 FGD mist eliminators (1st and 2nd stages) (Exhibit A-12, Schedule B5.1, page 4, line 44). The original mist eliminator trays had become plugged, damaged, and worn. They were replaced to improve FGD moisture removal and emission monitoring equipment reliability and accuracy.

- The Monroe Unit 4 generator stator rewind was completed for $2.2 million (Exhibit A-12, Schedule B5.1, page 4, line 47). The stator required a rewind to maintain the generator's reliability and to address the deterioration of the brazed joints and excess coil movement.
- Procurement of a spare main unit transformer was continued for $3.9 million to replace the transformer that was installed on Monroe Unit 1 in the fall of 2021 (Exhibit A-12, Schedule B5.1, page 4, line 48). This transformer is needed to provide a fleet spare that will be installed in the event of a failure of one of the other main unit transformers.
- Monroe fuel supply tripper car gallery J had the floor replacement (7,199 square feet of elevated structure) completed for $4.1 million (Exhibit A-12, Schedule B5.1, page 4, line 49). The original tripper gallery floors, supporting floor beams, and floor beam top flanges had corroded over time and required replacement to ensure worker safety during washdown activities required to control fugitive and combustible coal dust. There are 9 galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery J was identified as a priority area in the inspection. Support beams and girders show signs of degradation and need to be replaced. This project restored the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.

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- Monroe fuel supply CV-04 transfer chute was replaced for $2.8 million (Exhibit A-12, Schedule B5.1, page 4, line 50). The new discharge chute technology minimizes combustible dust and coal spillage.
- Monroe fuel supply tripper car gallery B started engineering of the floor replacement (8,096 square feet of elevated structure) for $1.3 million (Exhibit A-12, Schedule B5.1, page 4, line 51). The original tripper gallery floors, supporting floor beams, and floor beam top flanges had corroded over time and required replacement to ensure worker safety during washdown activities required to control fugitive and combustible coal dust. There are nine (9) galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery B was identified as a priority area in the inspection. Support beams and girders show signs of degradation and need to be replaced. This project will restore the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.
- The Monroe fuel supply coal pile runoff oil wastewater system began initial engineering and material procurement for $1.1 million (Exhibit A-12, Schedule B5.1, page 4, line 52).

In 2017 the plant experienced a Notice of Violation on a similar system. Remediation of soil and augmentations to the wastewater system were required following the event. Further review of oil-containing equipment on

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the Monroe property identified the areas around the coal pile run-off system are at risk of a similar event. A major oil spill event into public waterways could result in cleanup costs into the millions as well as fines for not mitigating this potential risk.

The current coal pile run-off wastewater treatment system has no oil removal capabilities to prevent oil discharges into open waters. The coal pile containment area contains over 30,000 gallons of oil stored in various locations. Any loss of oil from these systems could migrate to the coal pile run-off water collection system.

Currently, discovery of oil-contaminated water in the coal pile run-off wastewater system requires an operator to be at the right place at the right time. Detecting small quantities of oil sheen is very difficult and heavily influenced by environmental conditions, including daylight, rain, fog, etc. Once the operator discovers that the contamination exists, they manually intervene by deploying oil-containment booms and contracting environmental clean-up firms to mitigate the event.

The planned project installs an oily waste treatment system that has automated oil removal capabilities for the coal pile run-off system. The new system will not depend on visual observations and manual intervention to trigger an oil clean-up response. Instead, the oily waste treatment systems will provide 24x7 enhanced environmental protection.

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The detailed discussion above is responsive to the Final Order dated December 1, 2023, in Case No U-21297 in which the Commission indicated support for necessary measures to prevent environmental contamination and damage, but it felt that risk analysis of an environmental spill needed further specificity for this project.

Q75. What are the routine projects with projected capital expenditures greater than $1 million planned or completed for 2023 for Steam Power Generation?

A75. Planned or completed 2023 routine capital projects greater than $1 million are detailed on page 5 of Exhibit A-12, Schedule B5.1 and discussed below.

- In preparation for the Belle River Unit 2 2024 periodic outage, Belle River Unit 2 LP turbine rotors and blades procurement payments were projected for materials at $6.1 million (Exhibit A-12, Schedule B5.1, page 5, line 68). Inspections have identified blade erosion and rotor cracking that needs to be addressed to ensure continued safe and reliable operation of the LP turbines. This work is a permanent fix to the issues identified in 2020. Additionally, $2.3 million was projected to procure materials for the replacement of the Belle River Unit 2 exciter (Exhibit A-12, Schedule B5.1, page 5, line 69). Vibration levels have indicated structural/mechanical integrity issues with the rotor components. Replacement of the exciter will maintain equipment reliability in the future. $1.5 million was projected to start procurement of materials for the waterwall tubes that will be replaced on Belle River Unit 2 in 2024 (Exhibit A-12, Schedule B5.1, page 6, line 70). The project will replace 2,500 square feet of boiler waterwall panels damaged by quench cracking and soot blower erosion to support continued reliable boiler operation. Finally, $1.5 million was projected to procure materials for the Belle River Unit 2 intermediate pressure (IP) turbine valves (Exhibit A-12, Schedule B5.1, page 5, line 71). This project overhauls the four (4) IP turbine stop valves and four (4) control valves. The valves are worn and require overhaul to operate properly. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.

- $3.3 million was projected to finish the separation of St. Clair Power Plant from the Fuel Supply system (Exhibit A-12, Schedule B5.1, page 5, line 72). There are a number of systems in the St. Clair Fuel Supply system that are interrelated with the Belle River Power Plant. Although St. Clair Power Plant retired in 2022, these interrelated systems must remain functional to continue fueling the Belle River Power Plant. The project scope was to completely isolate St. Clair Power Plant from the Fuel Supply System. This scope included fire protection and general service water, wastewater and stormwater, low voltage electrical, and medium voltage electrical switchgear.
- Installation of a wet dust collector to replace three (3) dry-type dust collectors in the Belle River fuel supply 3TH-9 building was projected for $1.8 million (Exhibit A-12, Schedule B5.1, page 5, line 73). The prior system had inadequate performance to meet current NFPA guidelines. The replacement mitigates combustible dust and complies with the NFPA combustible dust guidelines.
- In preparation for the Greenwood Unit 1 2024 periodic outage, $5.8 million was spent on material progress payments for procurement of the LP turbine

rotors and blades (Exhibit A-12, Schedule B5.1, page 5, line 74). Stress corrosion cracking of multiple blade root connections needs to be addressed to ensure continued safe and reliable operation of the LP turbines.

- Monroe Unit 1 waterwall replacement was completed for $15.0 million (Exhibit A-12, Schedule B5.1, page 5, line 75). The project replaced 4,000 square feet of boiler waterwall tubes. The boiler tubes were deteriorated due to corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning.
- Monroe Unit 1 LP turbine rotors and blades were replaced to address the industry-wide safety concern with known stress corrosion cracking for $10.4 million (Exhibit A-12, Schedule B5.1, page 5, line 76). Prior inspections revealed extensive erosion on the L-0 through L-5 blade rows. These rotors will be further analyzed for the severity of stress corrosion cracking and refurbished for use on the Monroe Unit 4 LP turbine in 2025 to minimize the project cost needed to address stress corrosion cracking on its LP turbine forgings.
- Monroe Unit 1 reheat outlet pendants were replaced for $5.4 million (Exhibit A-12, Schedule B5.1, page 5, line 77). The boiler reheater tubes are critical to steam turbine design and operations. Reheater tubes allow exhaust steam from the HP turbine to be reheated in the boiler and reintroduced into the IP and LP turbines with additional energy that adds to unit MW output at improved efficiency levels. The replacements were based on near term tube failure risk which would force the unit offline for repair.
- Thirty-seven (37) expansion joints were replaced on Monroe Unit 1 for $5.3 million (Exhibit A-12, Schedule B5.1, page 5, line 78). This project covered

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multiple areas in the air duct and flue gas systems to accommodate thermal expansion of the process ductwork. Scope of work included ash removal to provide a safe workspace, confined space rescue services, scaffold for safe access, lead/asbestos abatement, and replacement of the expansion joints. The replacements were based on near term failure risk which would affect unit reliability, efficiency, and result in a safety risk to plant personnel.

- $4.2 million was spent to complete the replacement of the Monroe Unit 1 coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page 5, line 79). The previous ductwork had thinned, resulting in fugitive dust leaks, and required replacement.
- $3.9 million was spent to procure and replace blade rows 1, 3, and 8 on the Monroe Unit 1 HP turbine (Exhibit A-12, Schedule B5.1, page 5, line 80). The turbine blades were replaced due to solid particle erosion. The replacement was required to sustain the HP turbine reliability.
- Monroe Unit 1 IP turbine blades (Exhibit A-12, Schedule B5.1, page 5, line 81) were replaced for $3.7 million. The turbine blades were replaced due to solid particle erosion. The first stage rows on both ends (turbine-end and generator-end) were replaced. The replacement was required to sustain the IP turbine reliability.
- Monroe Unit 1 SCR catalyst modules for layers 1, 2, and 4 were replaced for $3.3 million (Exhibit A-12, Schedule B5.1, page 5, line 82). The catalyst module replacements were required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- Monroe Unit 1 IP turbine rotor project (Exhibit A-12, Schedule B5.1, page 5, line 83) started progress payments of $2.6 million to replace the rotor in

2025. During off-site inspection in 2023, creep void indications of cracking were found in the rotor bore and the stage 1 wheel dovetail roots. The OEM performed the work required to return the IP rotor to service on a short term basis but also provided further analysis of the rotor that confirmed the need to replace the rotor soon, concluding that it could only be safely operated for an additional 30 months.

- Monroe Unit 1 economizer tubes were replaced for $2.5 million (Exhibit A-12, Schedule B5.1, page 5, line 84). The boiler economizers are a critical component of the boiler tubing circuits that removes waste heat from the combustion process and utilizes it to preheat boiler feedwater improving overall cycle efficiency and heat rate. The original equipment economizer had erosion and tube thinning which required approximately 2,000 linear feet of tubing replacements to maintain boiler reliability.
- The Monroe Unit 1 reheat turbine stop valves (Exhibit A-12, Schedule B5.1, page 5, line 85), control valves (Exhibit A-12, Schedule B5.1, page 5, line 88), and main steam stop valves (Exhibit A-12, Schedule B5.1, page 6, line 89) were rebuilt for $2.4 million, $1.3 million, and $1.3 million, respectively. All turbine valves must operate properly to provide overspeed protection for the turbine and prevent possible catastrophic failure.
- Monroe Unit 1 SCR inlet and outlet dampers were removed for $1.5 million (Exhibit A-12, Schedule B5.1, page 5, line 86). When the SCR was originally installed, these dampers and the SCR only operated during summer months. Now, since the SCR is operated year-round due to changes in EPA regulations, the inlet and outlet dampers are not needed and

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contribute to draft losses leading to ID fan limitations, negatively affecting the output capability of the generating unit.

- The Monroe Unit 1 south air heater hot and cold end baskets were replaced for $1.4 million (Exhibit A-12, Schedule B5.1, page 5, line 87). The previous baskets were degraded due to corrosion and, if not addressed, would have become loose and cause an imbalance leading to an air heater drivetrain failure. The replacements restored physical integrity and heat transfer efficiency of the air heater.
- Monroe Unit 1 coal mill silo 1-3 (Exhibit A-12, Schedule B5.1, page 5, line 90) and Monroe Unit 4 coal mill silo 4-1 (Exhibit A-12, Schedule B5.1, page 5, line 105) were projected to be rebuilt for $1.2 million and $1.5 million, respectively. The chemical and abrasive properties of coal within the silos resulted in corrosion and erosion of the silo walls and compromised the structural integrity requiring repairs.
- Monroe Unit 1 turning gear and bull gear were rebuilt for $1.2 million (Exhibit A-12, Schedule B5.1, page 5, line 91). The turbine turning gear must engage to the bull gear as designed to rotate the turbine shaft properly when the unit is offline to prevent damage to the turbine shaft. To address the excessive wear on these components, the turning gear was overhauled and bull gear was replaced.
- Monroe Unit 1 FGD mist eliminators (1st and 2nd stages) were replaced for $1.1 million (Exhibit A-12, Schedule B5.1, page 5, line 92). The original mist eliminator trays were plugged, damaged, and worn. They were replaced to improve FGD moisture removal and emission monitoring equipment reliability and accuracy.

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- $1.1 million was spent to replace the Unit 1 FGD absorber inlet expansion joint and flanges on both upstream and downstream sides of the joint (Exhibit A-12, Schedule B5.1, page 5, line 93). The inlet expansion joint is essential for inlet flue gas to reliably enter the absorber tower. It allows for expansion and contraction of the inlet duct with changing temperatures (during a shutdown/startup of the unit). The previous expansion joint was deteriorated and showed visible signs of failure. Failure of this expansion joint will result in flue gas leaking from the ductwork and poses a reliability risk.
- The Monroe Unit 1 north and south FGD booster fans were rebuilt for $1.1 million (Exhibit A-12, Schedule B5.1, page 5, line 94). The FGD system for each unit includes a north and south booster fan. These axial fans, with a 14-foot diameter impeller, are located between the outlet of the precipitator and the inlet to the FGD Absorber. Failure of one of these booster fans would cause the unit to be limited to half load until replacement parts could be procured and installed. Due to the corrosive environment in which these fans operate, the fans require repair or replacement of the hub and blades every 8 years to maintain reliability. This maintenance was due in 2023.
- $1.2 million was spent to start procurement of materials in preparation to replace the Monroe Unit 2 air heater cold end baskets (Exhibit A-12, Schedule B5.1, page 5, line 95) in 2024. The air heater plays a critical heat transfer role to boiler efficiency and flue gas equipment operational performance. The Monroe units cold end baskets typically last 7-10 years. The cold-end baskets on Monroe Unit 2 north and south air heaters have been in service since 2014 and are currently in failure mode due to a

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significant loss (30 percent) of element material. As this condition progresses, so does the risk of an out of balance condition, placing high stresses on all components of the air heater. The imbalance issue will lead to drive train failures, resulting in unit forced outages.

- In preparation for the Monroe Unit 3 outage in 2024, new air heater cold end baskets were purchased for $2.2 million (Exhibit A-12, Schedule B5.1, page 5, line 96). The cold-end baskets on Monroe Unit 3 north and south air heaters have been in service since 2015 and are currently in failure mode due to a significant loss (30 percent) of element material. Additionally, the purchase of SCR catalyst modules for layers 2, 3, and 4 are projected for $1.5 million (Exhibit A-12, Schedule B5.1, page 5, line 97). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines. $1.3 million was projected to start engineering and procure material to replace twelve (12) Monroe Unit 3 expansion joints (Exhibit A-12, Schedule B5.1, page 5, line 98). The replacements are required to maintain unit reliability and efficiency, while also mitigating safety risks to plant personnel. Finally, $1.1 million was projected to be spent to start engineering and begin to procure materials to replace the Monroe Unit 3 existing coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page 5, line 99). The existing ductwork is thinning, causing fugitive dust leaks, and requires replacement.
- Monroe Unit 3 coal mill 3-6 overhaul was projected for $1.0 million. The coal mill overhaul was due to service hours, air flow performance, and lube oil analysis indications of deteriorating internal components (Exhibit A-12, Schedule B5.1, page 5, line 100). Due to the abrasiveness of coal, coal mill

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parts experience significant wear in the process of converting lump coal to a fine powder consistency suitable for boiler combustion and need to be disassembled, repaired, and components replaced approximately every 10 years.

- In preparation for the Monroe Unit 4 2025 periodic outage, $4.3 million was spent to start procurement of long lead materials related to refurbishment of the LP turbines (Exhibit A-12, Schedule B5.1, page 5, line 101). Refurbishment is needed due to the industry-wide problem of stress corrosion cracking on the current LP turbine. The rotors being replaced on Monroe Unit 1 in 2023 will be analyzed, refurbished, and installed on Monroe Unit 4 to keep the project cost to a minimum while mitigating the safety risk of a stress corrosion cracking catastrophic failure.
- Installation of SCR catalyst modules for layer 2 for Monroe Unit 4 was projected to cost $2.1 million (Exhibit A-12, Schedule B5.1, page 5, line 102). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- Monroe Unit 4 south boiler feed pump turbine condenser retubing was projected to cost $1.8 million (Exhibit A-12, Schedule B5.1, page 5, line 103). A significant increase in tube failures in the inlet section of the condenser were identified resulting in thirty-nine (39) percent of the condenser inlet section tubes being plugged, requiring the condenser to be retubed to keep the boiler feed pump turbine in service.
- In preparation for the Monroe Unit 4 outage in 2025, $1.5 million was projected to be spent to start engineering and material procurement of SCR catalyst module layers 1, 3, and 4 that will be replaced (Exhibit A-12,

Schedule B5.1, page 5, line 104). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.

- Procurement of a spare main unit transformer was completed for $3.0 million to replace the transformer that was installed on Monroe Unit 1 in the fall of 2021 (Exhibit A-12, Schedule B5.1, page 5, line 106). This transformer is needed for fleet reliability in the event of a failure of one of the other main unit transformers.
- Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1, page 5, line 107) will be removed and replaced with an above ground storage tank for a projected $2.0 million. The tank collects used oil, is constructed of double-walled steel, has a capacity of 5,750 gallons and has been in service since 1993. This project will mitigate the oil spill risk and ensure continued environmental compliance.
- The Monroe fuel supply coal pile runoff oil wastewater system replacement project was projected to continue with construction at a cost of $4.6 million (Exhibit A-12, Schedule B5.1, page 5, line 108). As previously discussed above in the 2022 steam routine projects section, this project enhances environmental compliance by reducing the risk of oil contaminants from the storm water and coal pile run-off systems reaching the lake.
- Monroe fuel supply tripper car gallery B floor replacement (8,096 square feet of elevated structure) was completed for $3.0 million (Exhibit A-12, Schedule B5.1, page 5, line 109). The original tripper gallery floors, supporting floor beams, and floor beam top flanges had corroded over time and required replacement to ensure worker safety during washdown

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activities required to control fugitive and combustible coal dust. There are 9 galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery B was identified as a priority area in the inspection. Support beams and girders showed signs of degradation and needed to be replaced. This project restored the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.

- Monroe fuel supply transfer chute that feeds from conveyor C4 to conveyors C5 and C5A was projected to be replaced for $2.7 million (Exhibit A-12, Schedule B5.1, page 5, line 110), the transfer chutes from conveyors C10, C11, and C5 that feed onto conveyor C4 were replaced for $2.0 million (Exhibit A-12, Schedule B5.1, page 5, line 111), and transfer chute from conveyor C19 that feeds onto conveyor C10 was projected to be replaced for $1.5 million (Exhibit A-12, Schedule B5.1, page 5, line 113). Transfer chutes are used throughout the fuel supply system to direct coal from one conveyor belt to another on the path from the coal piles to the powerhouse. The previous chute tended to generate significant amounts of coal dust during periods of dry coal and was prone to pluggage during periods of wet coal. The new discharge chute technology minimizes combustible dust and coal spillage and ensures compliance with NFPA guidelines.
- In preparation for the Monroe fuel supply tripper car gallery C floor (Exhibit A-12, Schedule B5.1, page 5, line 112) being replaced in 2024, $1.7 million

was spent for engineering and materials (10,750 square feet of elevated structure). The original tripper gallery floor, supporting floor beams, and floor beam top flanges have corroded over time and require replacement to ensure worker safety during washdown activities required to control fugitive and combustible coal dust. There are 9 galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery C was identified as the next priority area in the inspection. Support beams and girders show signs of degradation and need to be replaced. This project will restore the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.

- The capping of section 1a at Sibley Quarry was projected for $9.6 million (Exhibit A-12, Schedule B5.1, page 5, line 126). This portion of the site, twenty-seven (27) acres, has reached its licensed capacity and requires capping per its landfill operating permit.

Q76. What are the routine projects with projected capital expenditures greater than $1 million planned for 2024 for Steam Power Generation?

A76. Planned routine capital projects greater than $1 million for 2024 are detailed on page 6 of Exhibit A-12, Schedule B5.1 and discussed below.

- In preparation for the 2025 periodic outage on Belle River Unit 1, engineering and material procurement will be initiated to replace sixty-seven

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(67) 480-volt breakers (Exhibit A-12, Schedule B5.1, page 6, line 128) and fifty-three (53) medium voltage breakers (Exhibit A-12, Schedule B5.1, page 6, line 129) for $2.0 million and $1.9 million, respectively. The breakers are original to the 1980's era unit and the reliable operation of these breakers is at risk due to their age. These breakers are obsolete and no longer supported by the OEM. Additionally, these breakers are an electrical safety concern due to the obsolete trip device technology. Finally, $1.3 million will be spent to start material procurement for the Belle River Unit 1 east boiler feed pump turbine blades and rotor (Exhibit A-12, Schedule B5.1, page 6, line 130). During the 2022 Belle River Unit 1 periodic outage, the east boiler feed pump turbine rotor was inspected, and heavy rubbing was found on multiple stages where the blades connect to the rotor steeples. Crack indications were found and removed as a temporary repair, enabling the equipment to return to service with a plan for replacement during the 2025 periodic outage.

- $1.1 million will be spent to rebuild the white coal mill on Belle River Unit 1 due to service hours and lube oil analysis indications of deteriorating internal components (Exhibit A-12, Schedule B5.1, page 6, line 131). Due to the abrasiveness of coal, coal mill parts experience significant wear in the process of converting lump coal to a fine powder consistency suitable for boiler combustion and need to be disassembled, repaired, and components replaced approximately every 10 years. The coal mill was last overhauled in 2014 and has close to 50,000 run hours.
- The Belle River Unit 2 LP turbine rotors and blades will be replaced for $6.4 million (Exhibit A-12, Schedule B5.1, page 6, line 132). Inspections have

identified blade erosion and rotor cracking that needs to be addressed to ensure continued safe and reliable operation of the LP turbines. This work is a permanent fix to the issues identified and repaired on a temporary basis in 2020.

- Waterwall tubes will be replaced on Belle River Unit 2 for $4.3 million (Exhibit A-12, Schedule B5.1, page 6, line 133) to support continued reliable boiler operation. The project will replace 2,500 square feet of boiler waterwall panels damaged by quench cracking and soot blower erosion.
- $3.3 million will be spent to replace the Belle River Unit 2 exciter with a static exciter (Exhibit A-12, Schedule B5.1, page 6, line 134). Vibration levels have indicated structural and mechanical integrity issues with the rotor components. Replacement of the exciter will maintain equipment reliability in the future.
- Belle River Unit 2 IP turbine valves will be overhauled for $2.8 million (Exhibit A-12, Schedule B5.1, page 6, line 135). This project overhauls the four (4) IP turbine stop valves and four (4) control valves. The valves are worn and require overhaul to operate properly. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.
- The Belle River Unit 2 turbine stop valve actuators will be replaced for $2.7 million (Exhibit A-12, Schedule B5.1, page 6, line 136). The original actuators provided by the OEM have been replaced across the industry due to maintenance issues, lack of spare parts, and an absence of qualified companies capable of repairing them. The replacements are required to maintain continued reliable operation of this system that controls turbine

loading. Failure of these valves to properly operate would impact the ability to properly control unit output. These valves also provide overspeed protection for the turbine and prevent possible catastrophic failure.

- In preparation for the 2026 periodic outage on Belle River Unit 2, engineering and material procurement will be initiated to replace sixty-seven (67) 480-volt breakers (Exhibit A-12, Schedule B5.1, page 6, line 137) and fifty-three (53) medium voltage breakers (Exhibit A-12, Schedule B5.1, page 6, line 138) for $2.0 million and $1.8 million, respectively. The breakers are original to the 1980's era unit. The reliable operation of these breakers is at risk due to their age. These breakers are obsolete and no longer supported by the OEM. Additionally, these breakers are an electrical safety concern due to the obsolete trip device technology.
- Over 400 primary superheater tube bends will be replaced on Belle River Unit 2 for $1.7 million (Exhibit A-12, Schedule B5.1, page 6, line 139). The tubes have been compromised from soot blower erosion and require replacement to support continued reliable boiler operations.
- In preparation for dual-unit outages in 2025 and 2026 at Belle River Power Plant, engineering and material procurement will be initiated to replace ninety-four (94) common system 480-volt breakers (Exhibit A-12, Schedule B5.1, page 6, line 140) and fifty-seven (57) common system medium voltage breakers (Exhibit A-12, Schedule B5.1, page 6, line 141) for $2.7 million and $2.0 million, respectively. The breakers are original to the 1980's era units. The reliable operation of these breakers is at risk due to their age. These breakers are obsolete and no longer supported by the OEM.

Additionally, these breakers are an electrical safety concern due to the obsolete trip device technology.

- Underground storage tanks No. 387 and No. 388 (Exhibit A-12, Schedule B5.1, page 6, line 142) at Belle River Power Plant will be replaced for $1.9 million. The tanks have been in service for over 29 years. Underground storage tanks that have been in service for this many years have an increased risk of failure, potentially allowing the contents to leak, contaminating the soil and groundwater around the tank. Tank No. 387 contains gasoline fuel with a capacity of 4,000 gallons. Tank No. 388 contains diesel fuel with a capacity of 1,000 gallons. Additionally, underground storage tank No. 393 (Exhibit A-12, Schedule B5.1, page 6, line 143) will be replaced for $1.8 million. The tank contains used oil with a capacity of 2,300 gallons and has also been in service for over 29 years.
- $12.1 million will be spent on engineering and material procurement for the Greenwood Unit 1 LP turbine rotors and blades replacement project (Exhibit A-12, Schedule B5.1, page 6, line 148). Stress corrosion cracking of multiple blade root connections is being addressed to ensure continued safe and reliable operation of the LP turbines.
- Materials will be procured for the 2025 replacement of the Greenwood Unit 1 feedwater heater No. 6 (Exhibit A-12, Schedule B5.1, page 6, line 149) and feedwater heater No. 3 (Exhibit A-12, Schedule B5.1, page 6, line 150) for $1.6 million and $1.4 million, respectively. A leak in the shell of feedwater heater No. 6 was discovered in March 2023. Phased Array Ultrasonic Testing (PAUT) also identified an 8” long crack in the shell. Further PAUT testing found several smaller connected indications on the

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inside diameter of the shell. Additional borescope inspection revealed multiple internal weld cracks located between the desuperheating zone and the drain cooling zone of the feedwater heater. Feedwater heater No. 6 needs to be replaced to restore reliable service. The existing feedwater heater No. 3 is experiencing an increasing number of tube leaks and requires replacement to restore reliability. Both feedwater heaters take waste heat from the LP turbines and use it to preheat boiler feedwater, improving the overall efficiency of the steam power cycle. Steam turbine power cycles utilize feedwater heating in this manner.

- $1.5 million will be spent on Monroe Unit 1 to start material procurement for the SCR catalyst modules being replaced on layer 3 in 2025 (Exhibit A-12, Schedule B5.1, page 6, line 151). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- For the Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page 6, line 152), the Company will continue progress payments of $1.1 million to replace the rotor in 2025. During an offsite inspection in 2023, creep void indications of cracking were found in the bore and the stage 1 wheel dovetail roots. The OEM performed the work required to return the unit to service on a short-term basis but also provided further analysis of the rotor that confirmed the need to replace the rotor soon, concluding that it could only be returned to service for no more than 30 months.
- In preparation for the Monroe Unit 2 periodic outage in 2026, $8.3 million will be spent to start procurement of material to forge new LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 6, line 153). Replacement

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is needed due to the industry-wide problem of stress corrosion cracking on the current LP turbine forgings.

- $4.2 million will be spent to complete the replacement of the Monroe Unit 2 north & south air heater cold end baskets (Exhibit A-12, Schedule B5.1, page 6, line 154). The air heater plays a critical heat transfer role to boiler efficiency and flue gas equipment operational performance. The Monroe cold end baskets typically last 7-10 years. The cold-end baskets on Monroe Unit 2 north and south air heaters have been in service since 2014 and are currently in failure mode due to a significant loss (30 percent) of element material. As this condition progresses, so does the risk of an out of balance condition, placing high stresses on all components of the air heater. The imbalance issue will lead to drive train failures, resulting in unit forced outages.
- $3.0 million will be spent on Monroe Unit 2 to complete the replacement of layer 3 SCR catalyst modules (Exhibit A-12, Schedule B5.1, page 6, line 155). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- Monroe Unit 2 coal mill feeder controls will be replaced for $1.5 million (Exhibit A-12, Schedule B5.1, page 6, line 156). The current coal mill feeder controls for all seven (7) coal mills are original equipment (1970's). Reliability of this equipment has diminished, causing unit derates. Replacing the obsolete controls is needed to address the reliability issues. This controls project upgrade will improve reliability, accuracy of measuring coal flow, and boiler efficiency.

- $12.7 million will be spent to replace Monroe Unit 3 waterwall tubes (Exhibit A-12, Schedule B5.1, page 6, line 157). This project was reduced in scope based on the advanced unit retirement as previously discussed in Q70. The project will now only replace approximately 2,000 square feet of boiler waterwall tubes. In total, the waterwall section of a single Monroe unit consists of over 42,000 square feet of tubes joined together in the furnace area of the boiler. The waterwall tubes absorb heat from the combustion process to convert boiler water to steam, the basic process of the steam power cycle. A tube leak in any portion of the waterwall requires the unit to be removed from service for repair. The boiler tubes being replaced are deteriorating due to corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning.
- Replacement of the SCR catalyst modules for layers 1, 2, and 3 on Monroe Unit 3 will be completed for $6.7 million (Exhibit A-12, Schedule B5.1, page 6, line 158). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- $5.3 million will be spent to complete the replacement of the existing Monroe Unit 3 coal mill primary air (PA) ductwork (Exhibit A-12, Schedule B5.1, page 6, line 159). The existing ductwork is thinning, resulting in fugitive dust leaks, and requires replacement. This project scope includes removal and replacement of the interconnecting ductwork, slide gates, dampers, and expansion joints on the unit's seven coal mills.
- $5.0 million will be spent to overhaul the Monroe Unit 3 turbine valves (Exhibit A-12, Schedule B5.1, page 6, line 160). Project scope includes the

four (4) throttle valves, four (4) intercept valves, eight (8) governor valves, and two (2) reheat stop valves. The valves are worn and require overhaul to ensure proper operation until unit retirement. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.

- $4.3 million will be spent to complete the replacement of Monroe Unit 3 IP turbine blades to correct erosion damage on the existing blades (Exhibit A-12, Schedule B5.1, page 6, line 161).
- Twelve (12) Monroe Unit 3 expansion joints will be replaced for $3.3 million due to leakage or being at risk of near-term leaking (Exhibit A-12, Schedule B5.1, page 6, line 162). This project covers multiple areas in the air duct/flue gas systems to provide a means of thermal expansion of the process ductwork. Scope of work includes vacuuming of all areas to provide a safe workspace, confined space rescue services, scaffold for safe access, lead/asbestos abatement, and replacement of the expansion joints. The replacements are based on near term failure risk which would affect unit reliability, efficiency, and result in a safety risk to plant personnel.
- Monroe Unit 3 reheat outlet pendants will be replaced for $2.7 million (Exhibit A-12, Schedule B5.1, page 6, line 163). The boiler reheater tubes are critical to steam turbine design and operations. Reheater tubes allow exhaust steam from the HP turbine to be reheated in the boiler and reintroduced into the IP and LP turbines with additional energy that adds to unit MW output at improved efficiency levels. The replacements are based on near term tube failure risk which would force the unit offline for repair.

- $2.7 million will be spent to complete the replacement of the Monroe Unit 3 north & south air heater cold end baskets (Exhibit A-12, Schedule B5.1, page 6, line 164). The baskets are in failure mode with significant loss (30 percent) of element material. The baskets have been in service since 2015, having a 7-10 year life. The integrity, reliability, and efficiency of the Monroe Unit 3 north & south air heater cold-end baskets will be restored.
- Monroe Unit 3 horizontal reheater tubes (4,000 linear feet) will be replaced for $2.6 million (Exhibit A-12, Schedule B5.1, page 6, line 165). The horizontal reheater is located within the downdraft section of the boiler. These tubes require replacement to avoid tube failure outages. Tube failures occur from oxygen pitting corrosion, fly ash erosion, abrasive wear of closely spaced horizontal reheater and primary superheater tubes, and the use of sootblowers which operate to remove/prevent ash build-up.
- $2.6 million will be spent to complete the Monroe Unit 3 DCS and control room modifications (Exhibit A-12, Schedule B5.1, page 6, line 166). The equipment and software are at risk from a reliability perspective, requiring modifications to keep the plant's control systems reliable. The DCS hardware was last replaced over a decade ago and the associated software dates back to the 1980's. Additionally, the equipment is no longer supported by the vendor. As discussed in the preceding section, the Company has scaled back this project to focus on the critical work necessary to support continued operations to 2028.
- $2.4 million will be spent to replace the upper and lower bearings on Monroe Unit 3 coal mill classifiers (Exhibit A-12, Schedule B5.1, page 6, line 167). The rebuild cycle for the classifiers is based on bearing life

expectancy, OEM recommendations, and condition of the internal wear components. The classifier bearings are recommended for replacement every 10 years, and the Monroe Unit 3 bearings have been in service since 2015.

- Monroe Unit 3 coal mill 3-7 silo will be rebuilt for $1.5 million (Exhibit A-12, Schedule B5.1, page 6, line 168). The chemical and abrasive properties of coal within the silos resulted in corrosion and erosion of the silo walls creating coal leaks and compromised the structural integrity. Repairs are required for a safe workspace and continued reliable operation.
- In preparation for the Monroe Unit 4 2025 periodic outage, $6.0 million will be spent to start procurement of long lead materials related to refurbishment of the LP turbines (Exhibit A-12, Schedule B5.1, page 6, line 169). Refurbishment is needed due to the industry-wide problem of stress corrosion cracking on the current LP turbine which could result in unexpected catastrophic failure. The LP rotors that were installed on Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in 2023. Due to the cost of forging new rotors or the extended outage required to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors will be replaced with those that were removed from Unit 1. The Unit 1 rotors will be inspected and refurbished to provide safe and reliable operation of the Unit 4 LP turbines until the projected retirement of Unit 4 in 2028. In addition, SCR catalyst modules for layers 1, 3, and 4 will be purchased for $3.8 million (Exhibit A-12, Schedule B5.1, page 6, line 170). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines. $1.8

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million will be spent to start engineering and begin to procure materials to replace the Monroe Unit 4 existing coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page 6, line 171). The existing ductwork is thinning, resulting in fugitive dust leaks, and requires replacement. $1.4 million will be spent to procure materials for Monroe Unit 4 expansion joints to be replaced in 2025 (Exhibit A-12, Schedule B5.1, page 6, line 172). Fourteen (14) high priority Monroe Unit 4 expansion joints have been identified to be replaced due to leakage. A leak can affect unit reliability and efficiency, and result in a safety risk to plant personnel. Finally, $1.2 million will be spent to procure materials for the Monroe Unit 4 turbine valves project (Exhibit A-12, Schedule B5.1, page 6, line 173). Project scope includes the four (4) stop valves, four (4) control valves, and 2 combined reheat stop valves. The valves are worn and require overhaul for proper operation until the projected Unit 4 retirement. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.

- Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1, page 6, line 174) will be replaced with an above ground storage tank for $1.2 million. Tank No. 389 has been in service since 1993. The tank collects used oil and is constructed of double-walled steel. Tank No. 389 has a capacity of 5,750 gallons. This project will mitigate the oil spill risk and ensure continued environmental compliance.
- Monroe fuel supply tripper car gallery C will have the floor replacement (10,750 square feet of elevated structure) completed for $4.7 million (Exhibit A-12, Schedule B5.1, page 6, line 175). The original tripper gallery floor, supporting floor beams, and floor beam top flanges have corroded

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over time and require replacement to ensure worker safety during washdown activities required to control fugitive and combustible coal dust. There are 9 galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery C was identified as the next priority area in the inspection. Support beams and girders show signs of degradation and need to be replaced. This project will restore the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.

- $3.0 million will be spent in Monroe fuel supply to replace the transfer chutes in the CV-C2 Loading Zone (Exhibit A-12, Schedule B5.1, page 6, line 176). The CV-C2 loading zone transfer chutes design and technology is obsolete. This project replaces three (3) transfer chutes (C1A to CV-C2, C1B to CV-C2 & C1C to CV-C2) that load onto CV-C2 so that the transfer point is reconfigured such that the coal stream is less susceptible to dust generation, pluggage, and spillage.
- The Monroe fuel supply coal pile runoff oil wastewater system replacement project will be completed for $2.6 million (Exhibit A-12, Schedule B5.1, page 6, line 177). As previously discussed above in the 2022 steam routine projects section, this project enhances environmental compliance by reducing the risk of oil contaminants from the storm water and coal pile run-off systems reaching the lake.

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- The capping of section 1A at Sibley Quarry will be completed for $8.3 million (Exhibit A-12, Schedule B5.1, page 6, line 186). This portion of the site, twenty-seven (27) acres, has reached its licensed capacity and requires capping as it is no longer available for material disposal.

Q77. What are the routine projects with projected capital expenditures greater than $1 million to be executed in 2025 for Steam Power Generation?

A77. Planned maintenance projects greater than $1 million in 2025 are detailed on page 7 of Exhibit A-12, Schedule B5.1 and discussed below.

- $6.3 million will be spent on Belle River Unit 1 to complete replacement of waterwall tubes (Exhibit A-12, Schedule B5.1, page 7, line 188). The project will replace 2,500 square feet of boiler waterwall panels damaged by quench cracking and sootblower erosion to support continued reliable boiler operation.
- $5.3 million will be spent to replace baskets on Belle River Unit 1 secondary air heater (Exhibit A-12, Schedule B5.1, page 7, line 189). The baskets of the secondary air heaters have been in service for 10 years, have eroded, are loose and at risk of falling out, causing a forced outage. The integrity, reliability, and efficiency of the secondary air heater baskets will be restored with this project.
- Belle River Unit 1 IP turbine valves (Exhibit A-12, Schedule B5.1, page 7, line 190) will be overhauled for $4.5 million. The four (4) IP turbine control and four (4) stop valves begin to wear within 6 to 8 years of an overhaul and must be disassembled, inspected, and repaired every other periodic outage. The Unit 1 IP turbine control and stop valves need to operate

properly to provide overspeed protection for the turbine and prevent possible catastrophic failure.

- $3.3 million will be spent to replace the Belle River Unit 1 duplex heater (No. 1 and No. 2 low-pressure feedwater heater) (Exhibit A-12, Schedule B5.1, page 7, line 191). The low-pressure heaters are original plant equipment. Eddy current testing and borescope inspections of these heaters identified tube wall loss damage at the support plates. Replacement of the duplex heater is required to maintain unit performance.
- $2.6 million will be spent to replace Belle River Unit 1 expansion joints (Exhibit A-12, Schedule B5.1, page 7, line 192). This project replaces sixteen (16) expansion joints on the air side of the ductwork going to the boiler and on the gas side of the ductwork from the boiler. A comprehensive plan to identify and replace expansion joints on the air and gas ducts was developed and is being implemented to address leakage. The replacements are based on near term failure risk which would affect unit reliability, efficiency, and result in a safety risk to plant personnel.
- 792 linear feet of Belle River Unit 1 horizontal middle reheat tubes (Exhibit A-12, Schedule B5.1, page 7, line 193) will be replaced for $2.2 million. Corrosion and sootblower erosion have degraded the original 1980's era factory tube welds in the horizontal middle reheater.
- $2.4 million will be spent to complete the replacement of the Belle River Unit 1 east boiler feed pump turbine blades and rotor (Exhibit A-12, Schedule B5.1, page 7, line 194). During Belle River Unit 1's 2022 periodic outage, the east boiler feed pump turbine rotor was inspected and heavy rubbing was found on multiple stages where the blades connect to the rotor

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steeples. Crack indications were found and removed as a temporary repair enabling the equipment to return to service with a plan for replacement during the 2025 periodic outage.

- $5.0 million will be spent to cap 16 acres in Area G2 – Phase 2 at the Range Road Landfill with a 2-foot clay cover and a 6-inch layer of friable earth with vegetation cover (Exhibit A-12, Schedule B5.1, page 7, line 195). This work complies with the site landfill license from EGLE which requires sections of the landfill be capped as they are filled.
- Engineering and material procurement will continue for the replacement of the Belle River north auxiliary boiler (Exhibit A-12, Schedule B5.1, page 7, line 196) and Belle River south auxiliary boiler (Exhibit A-12, Schedule B5.1, page 7, line 197) for $1.9 million each. Both auxiliary boilers are original to the 1980's era plant. They have become unreliable due to frequent tube leaks, resulting in multiple tubes being plugged which significantly reduces boiler efficiency. As boiler efficiency is reduced, there is an increasing risk that the boilers will not provide sufficient steam for unit startups or building heat. Without sufficient building heat, there will be freezing damage to various plant systems and equipment and safety issues for plant personnel.
- $5.9 million will be spent to complete the Greenwood Unit 1 LP turbine rotors and blades replacement project (Exhibit A-12, Schedule B5.1, page 7, line 201). Stress corrosion cracking of multiple blade root connections is being addressed to ensure continued safe and reliable operation of the LP turbines.

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- Greenwood Unit 1 feedwater heater No. 6 (Exhibit A-12, Schedule B5.1, page 7, line 202) and feedwater heater No. 3 (Exhibit A-12, Schedule B5.1, page 7, line 203) will be replaced for $2.2 million and $2.1 million, respectively. A leak in the shell of feedwater heater No. 6 was discovered in March 2023. Phased Array Ultrasonic Testing (PAUT) identified an 8" long crack in the shell. Further PAUT scanning found several smaller connected indications on the inside diameter of the shell. Additional borescope inspection revealed multiple internal weld cracks located between the desuperheating zone and the drain cooling zone of the feedwater heater. The feedwater heater needs to be replaced to restore reliable service. The existing feedwater heater No. 3 is experiencing an increasing number of tube leaks and requires replacement to restore reliability. Both feedwater heaters take waste heat from the LP turbines and use it to preheat boiler feedwater improving the overall efficiency of the steam power cycle. All steam turbine power cycles utilize feedwater heating in this manner.
- The Greenwood Unit 1 turbine valves will be rebuilt for $1.8 million (Exhibit A-12, Schedule B5.1, page 7, line 204). The valves are worn and require overhaul to operate safely and properly. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.
- The Greenwood Unit 1 north boiler feed pump turbine last row of blades will be replaced for $1.5 million to correct erosion damage on the existing blades (Exhibit A-12, Schedule B5.1, page 7, line 205).
- $1.3 million will be spent to replace Greenwood Energy Center underground storage tank No. 377 (Exhibit A-12, Schedule B5.1, page 7, line 206). The

tank has been in service for over 30 years. Underground storage tanks that have been in service for this many years have an increased risk of failure, potentially allowing the contents to leak, contaminating the soil and groundwater around the tank. Tank No. 377 contains gasoline fuel with a capacity of 2,500 gallons.

- Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page 7, line 207) replacement will be completed for $4.2 million. During offsite inspection in 2023, creep void indications of cracking were found in the bore and the stage 1 wheel dovetail roots. The OEM performed the work required to return the rotor to service on a short-term basis but also provided further analysis of the rotor that confirmed the need to replace the rotor soon, concluding that it could only be returned to service for no more than 30 months.
- Monroe Unit 1 SCR catalyst modules for layer 3 will be replaced for $2.5 million (Exhibit A-12, Schedule B5.1, page 7, line 208). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- Monroe Unit 1 coal mill feeder controls will be replaced for $1.4 million (Exhibit A-12, Schedule B5.1, page 7, line 209). The current coal mill feeder controls for all seven (7) coal mills are original equipment (1970's). Reliability of this equipment has diminished, causing unit derates. Replacing the obsolete controls is needed to address the reliability issues. This controls project upgrade will improve reliability, accuracy of measuring coal flow, and boiler efficiency.

- In preparation for the Monroe Unit 2 periodic outage in 2026, \$11.0 million will be spent to continue procurement payments on material to forge new LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 7, line 210). Replacement is needed due to the industry-wide problem of stress corrosion cracking on the current LP turbine forgings. In addition, Monroe Unit 2 SCR catalyst modules for layers 1, 2, and 4 will be purchased for \$4.4 million (Exhibit A-12, Schedule B5.1, page 7, line 211). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines. Finally, \$3.0 million will be spent to purchase materials for replacing the Monroe Unit 2 north and south air heater hot-end baskets (Exhibit A-12, Schedule B5.1, page 7, line 212). The baskets have significant deterioration which limits heat transfer capability and impacts operational performance. The integrity, reliability, and efficiency of the Monroe Unit 2 north and south air heaters will be restored.
- \$5.3 million will be spent to complete the replacement of the Monroe Unit 4 LPA and LPB turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 7, line 213). Refurbishment is needed due to the industry-wide problem of stress corrosion cracking on the current LP turbine which could result in unexpected catastrophic failure. The LP rotors that were installed on Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in 2023. Due to the cost of forging new rotors or the extended outage required to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors will be replaced with those that were removed from Unit 1. The Unit 1 rotors

will be inspected and refurbished to provide safe and reliable operation of the Unit 4 LP turbines until the projected retirement of Unit 4 in 2028.

- $4.2 million will be spent to overhaul the Monroe Unit 4 turbine valves (Exhibit A-12, Schedule B5.1, page 7, line 214). Project scope includes the four (4) stop valves, four (4) control valves, and 2 combined reheat stop valves. The valves are worn and require overhaul for proper operation until unit retirement. These valves provide overspeed protection for the turbine and prevent possible catastrophic failure.
- Monroe Unit 4 SCR catalyst modules for layers 1, 3, and 4 will be replaced for $3.6 million (Exhibit A-12, Schedule B5.1, page 7, line 215). The catalyst module replacements are required to maintain compliance with air permit emission limits for NOx and ammonia slip guidelines.
- $2.6 million will be spent to complete the Monroe Unit 4 coal mill primary air duct and dampers project (Exhibit A-12, Schedule B5.1, page 7, line 216). The existing ductwork is thinning, resulting in fugitive dust leaks, and requires replacement.
- $2.4 million will be spent to complete replacement of Monroe Unit 4 expansion joints (Exhibit A-12, Schedule B5.1, page 7, line 217). Fourteen (14) high priority Monroe Power Plant Unit 4 expansion joints have been identified to be replaced due to leakage. A leak can affect unit reliability, efficiency, and result in a safety risk to plant personnel.
- $2.1 million will be spent to replace the Unit 4 FGD inlet expansion joint and flanges on both upstream and downstream sides of the joint (Exhibit A-12, Schedule B5.1, page 7, line 218). The inlet expansion joint is essential to reliability for inlet flue gas to enter the absorber tower. It allows for

expansion and contraction of the inlet duct with changing temperatures (during a shutdown/startup of the unit). The existing joint and flange surface is damaged and needs replacement to allow the joint to seal.

- $1.9 million will be spent to complete the Monroe Unit 4 DCS and control room modifications (Exhibit A-12, Schedule B5.1, page 7, line 219). The equipment and software are at risk from a reliability perspective, requiring modifications to keep the plant's control systems reliable. The DCS hardware was last replaced over a decade ago and the associated software dates to the 1980's. Additionally, the equipment is no longer supported by the vendor. The Company has scaled back this project to focus on the critical work necessary to support continued operations to 2028.
- The Monroe Unit 4 secondary heat exchanger (Exhibit A-12, Schedule B5.1, page 7, line 220) will be replaced for $1.9 million. The Unit 4 secondary heat exchanger is an original piece of equipment (1970's era) and provides process heat to the combustion coils that are needed for unit start-up and building heating which will continue to be needed after unit retirement. The existing secondary heat exchanger has become unreliable due to an increasing number of tube leaks. Replacement of the secondary heat exchanger will improve unit reliability and maintain building heating requirements.
- $2.1 million will be spent to install new piping within the Monroe urea to ammonia (U2A) systems (Exhibit A-12, Schedule B5.1, page 7, lines 221 and 222). The emergency cooling and condensate systems have started to leak and show heavy corrosion after 15 years of service. The U2A system is common to all four units and required to be operational at all times.

Shutdown of the U2A system results in forced outages to all four Monroe Power Plant units. This project will install new cooling water supply and condensate return lines supporting the four U2A reactors and restore reliable operations to this critical environmental control equipment.

- Monroe fuel supply tripper car gallery D will have the floor replacement (9,890 square feet of elevated structure) completed for $7.1 million (Exhibit A-12, Schedule B5.1, page 7, line 223). The original tripper gallery floor, supporting floor beams, and floor beam top flanges have corroded over time and require replacement to ensure worker safety during washdown activities required to control fugitive and combustible coal dust. There are 9 galleries (sections) in the tripper gallery that serve all four Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to determine the condition of the gallery and prioritize sections based on the results. The inspection included the gallery conveyor floor system, floor plates, and floor supporting structural steel. Gallery D was identified as the next priority area in the inspection. Support beams and girders show signs of degradation and need to be replaced. This project will restore the structural integrity of the floor, the floor beams, girders, and associated connection hardware for this gallery section.
- $1.9 million will be spent to replace the Fuel Supply Dust Collector No. 4 (Exhibit A-12, Schedule B5.1, page 7, line 224). The replacement will mitigate combustible dust and comply with the NFPA combustible dust guidelines.

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Routine Capital Expenditures - Hydraulic Power Generation

Q78. What were the Company's routine capital expenditures in 2022 for Hydraulic Power generation (Ludington)?

A78. During 2022, the Company's Energy Supply group's routine capital expenditures for the Ludington Pumped Storage facility were $13.0 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 8, column (b). Expenditures were related to unit and HVAC maintenance, powerhouse roof replacement, lower penstock expansion joint chamber water stop replacement, and controls upgrades and replacements.

Q79. What will be the Company's routine capital expenditures for Hydraulic Power Generation (Ludington) in the 24 months ending December 31, 2024?

A79. During the 24 months ending December 31, 2024, Energy Supply routine capital expenditures for the Ludington Pumped Storage facility are projected to be $19.3 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 8, column (e). Investments will be related to the replacements of the powerhouse roof, lower penstock expansion joint chamber water stop, barrier net panels, oil water separator, and control relays and performing unit maintenance and upgrades to auxiliary equipment.

Q80. What will be the Company's routine capital expenditures for Hydraulic Power Generation (Ludington) in the projected test year, the 12 months ending December 31, 2025?

A80. During the 12 months ending December 31, 2025, the Company's routine capital expenditures for the Ludington Pumped Storage facility are projected to be $10.8

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million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 8, column (f). Investments will be related to replacements of control relays, governors, barrier net panels, and oil water separator, as well as station power transformer and other unit maintenance.

Routine Capital Expenditures - Other Power Generation

Q81. What bulk electric system support is provided by the peaking units included in Other Power Generation?

A81. DTE Electric's fleet of peaking units are primarily valued for their capacity and ability to start up quickly and reliably in response to high peak customer demand and the variable circumstances on the Company's distribution system throughout its 7,600 square mile service territory. The safe, reliable operation of these peaking units is also an important factor in system balancing as additional intermittent resources are integrated into the grid.

Q82. What were the Company's routine capital expenditures greater than $1 million in 2022 for Other Power Generation?

A82. During 2022, the Company's routine capital expenditures for Other Power Generation units was $66.7 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, lines 9-10, column (b). These expenditures include the following projects that individually exceeded $1 million as detailed on page 4 of Exhibit A-12, Schedule B5.1:

- $6.5 million was spent to complete the Belle River 12-1 major overhaul (Exhibit A-12, Schedule B5.1, page 4, line 53). This work was required for continued safe and reliable operation. Major maintenance intervals for gas

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turbines are established by the cumulative run hours and startup sequences experienced.

- In preparation for the Belle River 12-2 Peaker major overhaul outage in 2023, \$2.1 million was spent to continue procurement of materials (Exhibit A-12, Schedule B5.1, page 4, line 54). This work was required for continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.
- \$2.0 million was spent to replace the generator field on Belle River 12-1 (Exhibit A-12, Schedule B5.1, page 4, line 55). This work was required for continued safe and reliable operation. Generator field replacements for gas turbines are established by the years of service and the frequency of start/stop cycles experienced by the unit.
- In preparation for combustion overhauls in 2023, material procurement was completed for Belle River 13-1 (Exhibit A-12, Schedule B5.1, page 4, line 56) and Greenwood 12-1 (Exhibit A-12, Schedule B5.1, page 4, line 57) Peakers for \$1.7 million each. The projects included the replacement of fuel nozzles, support housings, combustor baskets, transition pieces, as well as inner and outer transition seals. This work was required to ensure continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.
- Combustion overhauls were completed on Greenwood 11-1 (Exhibit A-12, Schedule B5.1, page 4, line 58) and Greenwood 11-2 (Exhibit A-12, Schedule B5.1, page 4, line 59) Peakers for \$1.5 million and \$1.2 million, respectively. These projects included the replacement of fuel nozzles, support housings, combustor baskets, transition pieces, as well as inner and

outer transition seals. This work was required for continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.

- The Renaissance Unit 4 (Exhibit A-12, Schedule B5.1, page 4, line 60) and Renaissance Unit 1 (Exhibit A-12, Schedule B5.1, page 4, line 62) Peakers (163 MW each) completed major overhauls for $13.5 million and $7.4 million, respectively. These were the first major maintenance overhauls since the units were installed in 2002. The overhauls were required to maintain the peakers' availability and included corrective maintenance on the compressor, combustion system, gas turbine blading, and hot gas path.
- In preparation for the Renaissance Unit 3 Peaker (163 MW) major overhaul in 2023, $9.7 million was spent to procure materials for the overhaul (Exhibit A-12, Schedule B5.1, page 4, line 61). This was the first major maintenance since the unit was installed in 2002. The overhaul was required to maintain peaker availability and includes corrective maintenance on the compressor, combustion system, gas turbine blading, and hot gas path.
- $3.6 million was spent for engineering and material procurement of the Renaissance Unit 3 Peaker exhaust cylinder and manifold replacement (Exhibit A-12, Schedule B5.1, page 4, line 63). Recent exhaust system inspections completed on Renaissance Unit 3 revealed degradation of components and struts, material distress, and weld cracks. The integrity of the exhaust turbine casing and cylinder were at risk of failure and required replacement.
- The exhaust silencers (baffles) on the Renaissance Unit 3 Peaker were replaced for $2.9 million (Exhibit A-12, Schedule B5.1, page 4, line 64).

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The exhaust silencer baffles were degrading, and inspections identified metal debris and insulation material loss. The new baffles improve sound attenuation of the unit, supporting permit compliance.

- $2.0 million was spent to start procurement of a Renaissance spare main unit transformer (Exhibit A-12, Schedule B5.1, page 4, line 65). The previous spare transformer will be installed on Renaissance Unit 1 in 2024. This transformer is needed for fleet reliability in the event of a failure of one of the other Renaissance main unit transformers.
- In preparation for replacing the exhaust silencers (baffles) on the Renaissance Unit 4 Peaker in 2023, $1.3 million of materials were procured (Exhibit A-12, Schedule B5.1, page 4, line 66). The previous exhaust silencer baffles were degraded, and inspections identified metal debris and insulation material loss. The new baffles improve sound attenuation of the unit, supporting permit compliance.

Q83. What are the routine projects with projected capital expenditures greater than $1 million in 2023 for Other Power Generation?

A83. Planned 2023 Other Power Generation maintenance projects greater than $1 million are detailed on page 5 of Exhibit A-12, Schedule B5.1 and described below. The individual projects with greater than $1 million expenditures in 2023 for Other Power Generation units include:

- A Belle River 12-2 Peaker major overhaul outage was completed in 2023 for $5.4 million (Exhibit A-12, Schedule B5.1, page 5, line 114). Additionally, the Greenwood 11-1 Peaker will prepare for a 2024 major overhaul outage with engineering for $1.4 million (Exhibit A-12, Schedule B5.1, page 5, line

117). This work is required for continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.

- During the annual borescope inspection, emergent work was found to be required for the Belle River 13-1 Peaker Modified Hot Gas Path Overhaul and is projected for $1.4 million (Exhibit A-12, Schedule B5.1, page 5, line 115). Hardware damage as the result of a failed transition piece end seal, which was found in good condition in the spring borescope inspection, was identified within the combustion and turbine sections. The transition seal will be repaired, damaged 1st stage buckets will be replaced, and minor damage on the 2nd and 3rd stage hardware will be addressed.
- The generator field was replaced on the Belle River 12-2 (Exhibit A-12, Schedule B5.1, page 5, line 116) Peaker for $1.4 million. This work was required for continued safe and reliable operation. Generator field replacements for gas turbines are established by the years of service and the frequency of start/stop cycles experienced by the unit.
- The generator field was replaced on the Northeast 13-2 Peaker for $1.6 million (Exhibit A-12, Schedule B5.1, page 5, line 118). This work was required to replace failed equipment and for continued safe and reliable operation. The generator field failed in 2022 and required replacement.
- The Renaissance Unit 4 Peaker (163 MW) generator stator was rewound and the rotor was replaced (Exhibit A-12, Schedule B5.1, page 5, line 119) with a projected $9.2 million project expense. This rewind and rotor replacement was required because Renaissance Unit 4 experienced a ground fault on the generator. During the inspection phase of the project, the neutral side main

leads were found to have flashed between two phases, damaging insulation material and stator components.

- The Renaissance Unit 3 Peaker (163 MW) completed a major overhaul in 2023 for $7.1 million (Exhibit A-12, Schedule B5.1, page 5, line 120). This was the first major maintenance since the unit was installed in 2002. The overhaul was required to allow the return of the peaker to service and included corrective maintenance on the compressor, combustion system, gas turbine blading, and hot gas path.
- During the annual borescope inspection, emergent work was found to be required for the Renaissance Unit 2 Peaker (163 MW) Modified Hot Gas Path Overhaul and is projected for $3.7 million (Exhibit A-12, Schedule B5.1, page 5, line 121). Significant erosion with material loss was identified at the row 1 turbine vane trailing edges and at the row 1 turbine blade leading edges. Replacement of the row 1 vane and blade assemblies will be completed to address these issues.
- The exhaust silencer baffles on the Renaissance Unit 2 (Exhibit A-12, Schedule B5.1, page 5, line 122) and Renaissance Unit 4 (Exhibit A-12, Schedule B5.1, page 5, line 124) Peakers were replaced for $2.3 million and $1.7 million, respectively. The exhaust silencer baffles were degrading, and inspections identified metal debris and insulation material loss. The new baffles improved sound attenuation of the unit, supporting permit compliance.
- $1.8 million was spent to complete the Renaissance Unit 3 exhaust cylinder and manifold replacement (Exhibit A-12, Schedule B5.1, page 5, line 123). Exhaust system inspections completed on Renaissance Unit 3 revealed

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degradation of components and struts, material distress, and weld cracks. The inspections indicated the integrity of the exhaust turbine casing and cylinder were close to failure and required replacement.

- Procurement of a Renaissance unit compatible spare main unit transformer was completed for $1.2 million (Exhibit A-12, Schedule B5.1, page 5, line 125). This transformer was needed for fleet reliability in the event of a failure of any one of the Renaissance main unit transformers.

Q84. What are the routine projects with projected capital expenditures greater than $1 million in 2024 for Other Power Generation?

A84. Planned Other Power Generation maintenance projects greater than $1 million in 2024 are detailed on page 6 of Exhibit A-12, Schedule B5.1 and described below. The individual projects with greater than $1 million expenditures in 2024 for Other Power Generation units include:

- $3.7 million will be spent to complete the Blue Water Energy Center circulating water pumps enclosure project (Exhibit A-12, Schedule B5.1, page 6, line 144). Although the plant is designed to operate at minus 24 degrees Fahrenheit, the weather experienced in December 2022 revealed that certain wind direction and ice-forming conditions could still negatively impact plant reliability. During these conditions, the motor air filters on the circulating water pumps become plugged with ice which obstructs airflow and causes the motors to overheat and shutdown. Additionally, the cooling tower stairs, which are located immediately adjacent to the circulating water pumps, also experience heavy icing. Enclosing the circulating water pump, supporting systems, and the cooling tower stairs protects them from the cooling tower plume during the winter and will prevent forced outages and reduce the risk of employee injury.

- The Blue Water Energy Center conference room building (Exhibit A-12, Schedule B5.1, page 6, line 145) will be completed for $3.3 million. In the December 1, 2023 Commission Order from the last rate case No. U-21297, the Commission did not allow the inclusion of this project in rate base at that time due to what it considered insufficient information. To provide the further explanation and justification, the Company offers the following:

  The current office space configuration provides the fulltime employees of Blue Water with 25 available workspaces for their daily use. The 25 workspaces are at times not sufficient because the site workforce can surge to 100-plus personnel in support of routine and major maintenance activities.

  During construction of the plant, the large construction workforce used a significant number of temporary trailers for this purpose. Other DTE Electric power plant sites have repurposed original construction buildings that were converted to functional plant conference rooms when construction was completed.

  This new building will also support craft labor onboarding requirements, which include safety training and onsite orientation. Due to the open-air design of the Blue Water Energy Center, there are insufficient enclosed spaces available to support these onboarding requirements. Conversely, other DTE Electric power plant sites have historically utilized large open

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spaces that are inherent in the design of the plant boiler / turbine buildings to temporarily accommodate the needs of craft labor. A drawing of the conference building layout is provided in my workpapers in support of this project.

- $1.5 million will be spent for material procurement to replace the Blue Water Energy Center plant control system server (Exhibit A-12, Schedule B5.1, page 6, line 146). The current version of the Windows Operating System at Blue Water Energy Center is based on Microsoft Windows Server 2012 validated by General Electric at the time the Blue Water project was commenced. That version has a service end date of October 2023 and needs to be upgraded to maintain software security and reliability protocols.
- $1.1 million will be spent to start procurement of a spare Blue Water Energy Center steam turbine generator transformer (Exhibit A-12, Schedule B5.1, page 6, line 147). There is no transformer available that meets the electrical configuration requirements for the Blue Water Energy Center steam turbine generator. It is both reasonable and prudent to initiate the procurement of a spare transformer at this time, especially considering the multi-year manufacturing time requirement. A failed transformer could cause an extended forced outage of 2-3 years.
- A combustion overhaul will be completed on the Belle River 13-1 Peaker for $1.4 million (Exhibit A-12, Schedule B5.1, page 6, line 178). The project includes the replacement of fuel nozzles, support housings, combustor baskets, transition pieces, as well as inner and outer transition seals. This work is required for continued safe and reliable operation. Major

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maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.

- A blackstart peaker unit starting system will be replaced for $2.8 million (Exhibit A-12, Schedule B5.1, page 6, line 179). The unit starting system is obsolete and requires replacement with an up-to-date design. Components of the existing unit starting system, installed in 1999, are no longer supported by the OEM and other suppliers.
- Greenwood 11-1 Peaker major overhaul outage will be completed in 2024 for $6.8 million (Exhibit A-12, Schedule B5.1, page 6, line 180). This work is required for continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.
- The exhaust silencers (baffles) on the Greenwood 11-1, 11-2, and 12-1 Peakers will be replaced for $2.9 million (Exhibit A-12, Schedule B5.1, page 6, line 181). The exhaust silencer baffles are degrading, and inspections identified metal debris and insulation material loss. The new baffles will improve sound attenuation of the unit, supporting permit compliance.
- The generator field will be replaced on the Greenwood 11-1 (Exhibit A-12, Schedule B5.1, page 6, line 182) Peaker for $1.7 million. This work is required to ensure continued safe and reliable operation. Generator field replacements for gas turbines are established by the years of service and the frequency of start/stop cycles experienced by the unit.
- The Renaissance Unit 1 (Exhibit A-12, Schedule B5.1, page 6, line 183) and Renaissance Unit 3 (Exhibit A-12, Schedule B5.1, page 6, line 184) Peakers (163 MW each) generator stator rewind and rotor replacements will be

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completed for $7.4 million and $7.0 million, respectively. Previous inspections on Renaissance units revealed a high level of risk for in-service faults that need to be addressed to prevent failure. Accordingly, these units require a generator stator rewind and rotor replacement to avoid an in-service failure.

- The main unit transformer on the Renaissance Unit 1 Peaker will be replaced for $1.7 million (Exhibit A-12, Schedule B5.1, page 6, line 185). Transformer testing detected high internal gas levels, which is the leading indicator of transformer failure requiring replacement. The spare transformer utilized for this replacement was previously purchased and its planned use triggered the Company to purchase a replacement spare as discussed on page 116 of this testimony.

Q85. What are the routine projects with projected capital expenditures greater than $1 million in 2025 for Other Power Generation?

A85. Planned Other Power Generation maintenance projects greater than $1 million in 2025 are detailed on page 7 of 9 in Exhibit A-12, Schedule B5.1 and described below. The individual projects with greater than $1 million of expenditures in 2025 for Other Power Generation units include:

- Material procurement for a Blue Water Energy Center steam turbine generator transformer (Exhibit A-12, Schedule B5.1, page 7, line 198) and Blue Water Energy Center combustion turbine transformer (Exhibit A-12, Schedule B5.1, page 7, line 199) will continue for $1.9 million and $1.8 million, respectively. There are no transformers available for the Blue Water

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Energy Center combustion turbines and steam turbine generator. A failed transformer could cause an extended forced outage of 2-3 years.

- $1.7 million will be spent to complete the Blue Water Energy Center plant control system server upgrade (Exhibit A-12, Schedule B5.1, page 7, line 200). The current version of the Windows Operating System at Blue Water Energy Center is based on Microsoft Windows Server 2012 validated by General Electric at the time the Blue Water project was commenced. That version has a service end date of October 2023 and needs to be upgraded to maintain software security and reliability protocols.
- A blackstart peaker starting system will be replaced for $2.8 million (Exhibit A-12, Schedule B5.1, page 7, line 225). The unit starting system is obsolete and requires replacement with an up-to-date design. Components of the existing unit starting system, installed in 1999, are no longer supported by the OEM and/or other suppliers.
- The exhaust silencers (baffles) on the Delray 11-1 and 12-1 Peakers will be replaced for $1.9 million (Exhibit A-12, Schedule B5.1, page 7, line 226). The exhaust silencer baffles are degrading, and inspections identified metal debris and insulation material loss. The new baffles will improve sound attenuation of the unit, supporting permit compliance.
- In preparation for major overhauls in 2026, engineering will begin for the Greenwood 11-2 Peaker for $1.2 million (Exhibit A-12, Schedule B5.1, page 7, line 227) and 12-1 Peaker for $1.1 million (Exhibit A-12, Schedule B5.1, page 7, line 228). This work is required for continued safe and reliable operation. Major maintenance intervals for gas turbines are established by the cumulative run hours and startup sequences experienced.

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- $8.7 million will be spent to complete the Renaissance Unit 4 Peaker (163 MW) exhaust cylinder and manifold replacement (Exhibit A-12, Schedule B5.1, page 7, line 229). Exhaust system inspections completed on Renaissance Unit 4 and sister units have revealed degradation of components and struts, material distress, and weld cracks. The integrity of the exhaust turbine casing and cylinder are at risk of failure and require replacement.
- The Renaissance Unit 2 Peaker (163 MW) generator rotor will be replaced for $3.2 million (Exhibit A-12, Schedule B5.1, page 7, line 230). This generator work must be completed to correct the degradation of insulation and copper and reduce the risk of extensive damage should a failure occur.
- A blackstart peaker major overhaul outage will begin for $6.4 million (Exhibit A-12, Schedule B5.1, page 7, line 231) and be completed in 2026. This work is required for continued safe and reliable operation. Major maintenance intervals for peakers are established by the cumulative run hours and startup sequences experienced.

<u>**AFUDC Estimate**</u>

Q86. Do the capital expenditures you are supporting include an allowance for funds used during construction (AFUDC)?

A86. Yes, capital expenditures include an AFUDC for eligible projects that are in Construction Work in Progress (CWIP). At the direction of Company Witness Uzenski, AFUDC is applied to projects greater than $50,000 and lasting more than six months, except for large environmental projects which are exempt from AFUDC treatment.

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Q87. How much AFUDC is assumed in the projected test period for Energy Supply?

A87. AFUDC for Energy Supply is included on Exhibit A-12, Schedule B5.1, page 8 of 9. As shown on line 16, column (c), the AFUDC is projected to be $21.0 million for the 12-month period ending December 31, 2025. A historical trend is used to estimate AFUDC on routine capital since the mix of eligible projects is consistent year-to-year, while the AFUDC is calculated specifically on a project-by-project basis for eligible non-routine projects. The authorized cost of capital rate used is 5.561% consistent with the December 1, 2023 Case No. U-21297 Order. For additional details on AFUDC refer to Company Witness Uzenski's direct testimony.

Removal Costs, Plant in Service and CWIP Forecast

Q88. What is provided on the schedule entitled Removal Costs, Plant in Service, and CWIP schedule on page 9 of 9 of Exhibit A-12, Schedule B5.1?

A88. This schedule provides a breakdown of plant activities which are used by Witness Uzenski to forecast Plant in Service, Accumulated Depreciation, and CWIP on the projected balance sheet. Capital expenditures consistent with Exhibit A-12, Schedule B5.1, page 1 are summarized in columns (c) through (f). Column (b) includes a corresponding in-service assumption: Annual is indicated for categories of plant spend that are generally unitized within the year of spend, while a specific in-service date is used for projects that remain in CWIP for more than a year before moving into Plant in Service.

Column (g) includes an estimated percentage of removal costs that are included within the capital expenditures. Removal costs, as discussed by Witness Uzenski,

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are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore not depreciable. Removal cost of 15% based on historical trend of removals as a component of capital expenditures is applied to routine expenditures on lines 2 through 6. 100% is applied to specific removal and decommissioning projects on lines 9, 10, and 22 and 0% is applied to non-removal projects on lines 11 and 12. Finally, 0% is applied to new build projects on lines 15 through 21 since there is no related removal work.

Column (h) through (j) reflect calculated removal costs based on projected Capital Expenditures in columns (d) through (f) multiplied by the removal cost % in column (g). The remaining Capital Expenditures will appear in Plant in Service columns (k) through (m) if in-service assumption is "Annual", or CWIP columns (n) through (p) until the date of in-service as indicated in column (b). At that time, cumulative spend including the historical period is transferred to in-service (excluding the removal cost estimate). Major projects with a long lead time also reflect spend from earlier years that will be transferred out of CWIP into Plant in Service on the in-service date.

<u>Part III – Energy Supply Operation and Maintenance Expenses</u>

Q89. What is the process used to prepare the Energy Supply operating and maintenance (O&M) projected level of expense?

A89. Projected O&M expense is developed by taking historical test year O&M expenditure data and adjusting for any known projected period changes. Plant level changes include labor and material cost increases, cost variations related to environmental equipment operation, non-periodic maintenance cost variations driven by predictive maintenance programs, and other known changes.

The overall Energy Supply O&M projection for steam, hydraulic, and other generation assets is developed by adjusting the actual historic test year (2022) results for rate case adjustments between witnesses, normalization adjustments to the 2022 data, and known and measurable adjustments to handle O&M changes (up or down). O&M projections in this case do not include funding for Energy Supply renewable generation wind and solar assets that are handled in other regulatory filings.

Energy Supply operations expenses are those associated with day-to-day operation of the Company's generating units, including certain Account 501 fuel handling expenses. Energy Supply maintenance expenses are associated with periodic outages, non-periodic outages, and other maintenance activities. Other maintenance activities include standard day-to-day work to maintain plant equipment, such as inspections, servicing, and minor maintenance that does not require the unit to be taken offline to complete.

Energy Supply O&M is presented in three major cost categories as shown below:

- Steam Power Generation
- Hydraulic Power Generation
- Other Power Generation

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Q90. What were Energy Supply's historical O&M Expenditures for 2022 for Steam Power Generation?

A90. During 2022, Steam Power Generation adjusted O&M expenses totaled $231.5 million as shown on Exhibit A-13 Schedule C5.1, line 19, column (g). This was comprised of $105.2 million in operations costs and $126.3 million in maintenance costs. The $8.3 million of Steam Power Generation O&M that relates to Fuel Supply and Midwest Energy Resources Company (MERC) Fuel Handling is sponsored by Company Witness Milo on Exhibit A-13, Schedule C5.2 and is subtracted on line 20 (Note 1), resulting in remaining Steam Power Generation adjusted O&M in the amount of $223.2 million.

Q91. Can you provide an overview of Exhibit A-13, Schedule C5.1?

A91. Exhibit A-13, Schedule C5.1 shows total projected test period O&M for Steam Power Generation by starting with the 2022 actual O&M expenses and adjusting for rate case eliminations, normalization/other adjustments, and inflation adjustments. The historical adjustment is required to determine the portion of the 2022 O&M expenses that will reoccur in the 12-month period ending December 31, 2025. The normalization adjustment credit of $0.099 million is shown in note 4. There are also "Other" credit adjustments of $31.5 million required in column (k) and shown in note 6 to project the O&M required in the 12-month forecasted test period ending December 31, 2025.

Q92. What major O&M expense categories are found in Exhibit A-13, Schedule C5.1?

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A92. The expenses shown in Exhibit A-13, Schedule C5.1 are categorized into the major categories of operations and maintenance consistent with FERC accounting guidelines.

Operations account 500 includes the cost of plant management for the individual plant sites, their supporting staffs, and the Energy Supply Engineering Support Organization. Plant management includes plant site director, area managers, and administrative support. The major supporting staffs in this area are the technical and engineering personnel associated with problem solving daily plant operating issues, obtaining and interpreting test data, and developing long-term operating and maintenance plans to maintain plant availability and efficiency.

Operations account 501 "Fuel Handling" includes expenses incurred for coal train and vessel unloading, ash disposal, coal pile management, and mobile equipment operations. Depending on plant site and delivery options, plants maintain and manage a coal pile inventory that can vary over many months. Larger coal pile inventories are required at the Belle River Power Plant at the end of December to ensure adequate coal supplies when vessel deliveries cannot be obtained due to winter ice on the Great Lakes.

Accounts 502 and 505 represent operations personnel and materials expenses associated with direct operating supervision and control of boiler, turbine, generator, water, and environmental control systems. Shift supervisor and control room supervising operators are key to the successful steam power generation unit operations that are required to ensure adequate and cost-efficient production of electrical energy for our customers. Their labor expenses are captured in these accounts.

Account 506 "Misc. Steam Power Expenses" includes Instrument and Controls personnel to troubleshoot and calibrate the vast array of complex instruments and controls found on steam generating units. Also included in this account are operations of all common equipment such as water, air, and cooling equipment systems. Plant buildings and grounds cleaning, landscaping, snow removal, and maintenance are also captured in this account.

Maintenance accounts 510 through 514 capture expenses associated with planned and unplanned maintenance activities. These expenses mostly consist of the planned maintenance activities that generally occur on a two to five-year interval on all boiler systems and on a six to ten-year interval on turbine systems. Account 510 captures management of the plant maintenance area including area managers and general foremen. Account 511 covers maintenance of common infrastructure areas such as roofs, windows, and roads. The major area of expense captured in account 512 "Maintenance of Boilers" includes maintenance expenses for internal and external labor and all materials associated with planned and unplanned outage work on the boilers. The boiler maintenance scope of work includes the boilers, air and flue gas systems, ash handling, and fuel burning equipment. The major area of expense captured in account 513 "Maintenance of Electric Plant" includes internal and external labor and materials expenses associated with work on turbines. The major area of expense captured in account 514 "Maintenance of Misc. Steam Plant"

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includes internal and external labor and materials expenses for maintenance of all common equipment such as water, air, and cooling equipment systems.

Q93. Can you provide additional detail on the O&M expenses incurred for the Company's Steam Power Generation during 2022?

A93. Yes. In the historic period of 2022, the Company spent $223.2 million in Steam Power Generation O&M expenses after adjustments and reclassifications. Planned major periodic maintenance outages were executed in 2022 on Belle River Unit 1 and Monroe Unit 2. Also completed during 2022 were multiple short duration unit tune-up outages on various units to allow their continued efficient operation burning high percentages of lower sulfur coals. Costs for the portions of outages that occur in years other than 2022 will be captured in those years.

The other category of maintenance expenses incurred during the historic period were associated with regular plant maintenance while units were in operation or expenses to repair or replace equipment during a forced or unplanned unit outage. These short duration unplanned maintenance outages can generally be completed in three to seven days and will be experienced at varying intervals on all steam power generating units depending on the severity of the service cycles and the time elapsed since the last planned maintenance outage.

During the projected 12-month period ending December 31, 2025, the Company will execute major periodic maintenance outages on Belle River Unit 1, Greenwood Unit 1, and Monroe Unit 4, and minor periodic maintenance on Monroe Unit 1. As

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in the historic period, short duration unit tune-up outages will also be completed on various steam power generation units to optimize continuing performance.

Q94. What adjustments were made to the historical test period amounts?

A94. Fuel Handling O&M expenses recorded in Fuel Account 501 are added to Steam Power O&M in column (d). This amount includes Fuel Supply and MERC Fuel Handling for which an adjustment is made in column (e) to reclassify non-O&M fuel handling sponsored by Witness Milo (Note 3). In column (f) detailed in Note 4, there is one (1) historical adjustment:

- A credit for $99 thousand for the removal of EEI membership dues as supported by Witness Uzenski.

Q95. Can you describe some of the benefits the Company and its customers realize through its memberships in industry associations, such as the Electric Power Research Institute (EPRI)?

A95. Yes. As discussed by Witness Crozier, memberships in industry associations provide the Company access to benchmarking/best practices, research, and networking opportunities.

Specifically, with respect to EPRI, the Company collaborates with other utilities to fund technical projects that study and resolve critical industry issues. For instance, EPRI guidelines for boiler water chemistry and steam purity are commonly referenced to protect plant equipment and maintain reliable operations. In addition to the knowledge benefits gained through involvement in EPRI studies, the

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membership is cost-effective. The costs for the Company to perform even one of these projects would be greater than the cost of the membership.

Q96. What are the inflation factors shown in Note 5 of Exhibit A-13 Schedule C5.1?

A96. Note 5 contains the inflation factors that are utilized to forecast the changes necessary to transition needed O&M funding from the historic test year of 2022 to the projected test year ending December 31, 2025. The labor and material inflation adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 is supported by Witness Uzenski.

Q97. Can you provide a further explanation of the $31.5 million projected test year credit adjustment (reduction) shown on note 6 of Exhibit A-13, Schedule C5.1?

A97. Yes. The $31.5 million projected test year credit (reduction) adjustment shown in this exhibit reflects projected test year modifications needed to transition from 2022 actual O&M expenses to those required in the 12 months ending December 31, 2025. The labor and material inflation adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 is supported by Witness Uzenski:

- The first adjustment is a credit of $18.3 million and represents the St. Clair Power Plant's operation and maintenance expenses in 2022 that will not occur in the projected test period, as St. Clair Power Plant retired in 2022. A portion of St. Clair Power Plant's 2022 expenses are not included in the adjustment. The portion not included is $2.7 million of fuel supply costs common to St. Clair and Belle River Power Plants that were transferred to Belle River Power Plant because they are necessary for providing fuel to Belle River in the projected test year. The Belle River and St. Clair Power

Plants share a common coal vessel unloading facility that continues to be required to support the Belle River Power Plant after the St. Clair Power Plant retired.

- The second adjustment is a credit of $13.1 million and represents the Trenton Channel Power Plant's operation and maintenance expenses in 2022 that will not occur in the projected test period, as the Trenton Channel Power Plant retired in 2022. A portion of Trenton Channel Power Plant's 2022 expenses are not included in the adjustment. The portion not included is $0.4 million, representing Sibley Quarry's operation and maintenance costs. Sibley Quarry will continue operation beyond the date of the Trenton Channel Power Plant's retirement because it provides waste disposal services to Monroe Power Plant and other DTE business units.

Q98. Can you summarize Exhibit A-13, Schedule C5.4, entitled "Operations and Maintenance Expenses - Hydraulic Power Generation"?

A98. Exhibit A-13, Schedule C5.4 represents DTE Electric's share of the continuing operation and maintenance expense of the Ludington Pumped Storage facility. As a 49 percent owner of this facility, the Company incurs expenses for operating and maintaining the facility. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses adjusted for inflation. The labor and material inflation adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 is supported by Witness Uzenski. No other historical or projected adjustments were made to Hydraulic Power Generation Projected Operation and Maintenance expenses.

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Q99. Can you summarize Exhibit A-13, Schedule C5.5, entitled "Operations and Maintenance Expenses - Other Power Generation?

A99. Exhibit A-13, Schedule C5.5 represents DTE Electric's peaker fleet O&M costs, as well as Blue Water Energy Center, which began commercial operations in June 2022. DTE Electric owns and operates a quantity of peaking units ranging from 2.5 MW diesel-fueled engines to newer 163 MW natural gas-fired combustion turbines. The main driver of projections for these expenses through the projected test period is the labor and material required to support these peaker assets and Blue Water Energy Center. Included in this category will also be the labor expenses for the Generation Optimization and Integrated Resource Planning teams. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for inflation. The labor and material inflation adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 is supported by Witness Uzenski.

Q100. Did you make any adjustments to the historical test period operations and maintenance expenses for other power generation?

A100. Yes. I eliminated $37.7 million of total 2022 test year O&M, listed in column (d) of Exhibit A-13, Schedule C5.5 because these expenses are related to the renewable energy program which are not associated with the instant case.

Q101. What adjustments were made to the projected test period amounts for other power generation?

A101. In column (i) detailed in Note 3 of Exhibit A-13, Schedule C5.5, there is an upward adjustment for $6.3 million in support of Blue Water Energy Center's operation.

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Of the $6.3 million total adjustment, $4.67 million is in support of ongoing base operation and maintenance, while $1.67 million is in support of the estimated levelized major periodic O&M expense not covered by the contract service agreement with the OEM. The plant began commercial operations in June of 2022.

Also, $0.31 million is forecasted in 2025 to support of the first full year of Slocum BESS operations.

Finally, there is a decrease of $0.2 million related to the retirement and suspension of operations of peaker units (River Rouge 11, Slocum 11, and St. Clair 12 retirements and Fermi 11-3 and Fermi 11-4 suspension of operations).

Q102. What are your thoughts concerning the level of DTE Electric's historical and projected capital and O&M expenses contained in your testimony?

A102. DTE Electric has been reasonable and prudent in past capital and O&M expenditures, and I anticipate this to continue through the projected test period and beyond. During this same timeframe, generation unit availability is managed through a rigorous process that continues to be focused on prudent capital and O&M expenditures. I believe that DTE Electric has fully justified as reasonable and prudent its request for recovery of the Energy Supply plant expenses that are set forth in my testimony and associated exhibits.

Q103. Does this complete your direct testimony?

A103. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHANNEN M. HARTWICK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHANNEN M. HARTWICK

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Shannen M. Hartwick (she/her/hers), and my business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Electric Company (DTE Electric, DTEE or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from the University of Michigan with a Bachelor of Science in Engineering in 2007 and completed the Executive MBA program with the Ross School of Business at the University of Michigan in April 2023.

Q4. Please summarize your professional experience.

A4. I began my career with DTE Electric in 2008 and have been employed there since. I started out as an Associate Engineer in the Performance Management group where I worked on several process improvement projects across Distribution Operations. Over the years, I held a number of positions with increasing leadership responsibilities primarily within Distribution Operations and spent a year in DTE Electric's strategy team. Within Distribution Operations I worked in areas that include: Process Management Team, Substations, Asset Optimization (System Operations Center, Strategy, and dispatch), Southeast Service Operations and Tree Trim.

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In 2014, I took a position as a Developmental Field Supervisor – Southeast Service Operations where I was responsible for leading the frontline lineman performing maintenance, operations, and construction on DTE Electric's electrical distribution system.

In 2015, I was promoted to Manager – Tree Trim where I was responsible for leading Operations for the Tree Trim Team, comprised of DTE Energy Employees and all six of our tree trim vendors (comprising over 1300 tree trimmers in 2022). In this role, I was responsible for safety, quality, productivity, customer satisfaction, storm and trouble restoration efforts, and relationships with municipalities.

In 2020, I was promoted to the Director of Tree Trim where I was responsible for the strategy and execution of the Tree Trim Program. This included contract negotiations, strategy, planning, auditing, execution, outage restoration trimming, customer satisfaction, tree trim technology, and scheduling.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. Yes. I am a Lean Six Sigma Blackbelt.

Q6. What are your current duties and responsibilities?

A6. Currently, I am the Director of Automation. In this role, I am responsible for the execution of the distribution automation work. This includes overseeing

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automation program strategy and budget, engineering and planning, scheduling, construction, and in-servicing commissioning.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in Case numbers. U-20836 and U-21297. In addition, I supported the preparation of testimony on the topic of the Company's tree trimming program in previous rate cases (Case Nos. U-20162 and U-20561).

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support, as reasonable and prudent, the historical capital expenditures for 2022, projected capital expenditures for 2023 through December 31, 2025, in the distribution strategic investment category of the Technology and Automation Pillar, and the programs associated with the Company's Infrastructure Recovery Mechanism (IRM).

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring portions of Exhibit A-12 Schedule B5.4, Exhibit A-23 Schedule M7, and all of Exhibit A-19 as follows:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures, Distribution Plant – Technology and Automation (pg. 1-2,17-26)
A-23	M7	Distribution Plant Capital Project Detail – Technology and Automation
A-12	B5.4.1	Pilots: NWA: O'Shea Energy Storage
A-12	B5.4.2	Pilots: NWA: Battery Trailer
A-12	B5.4.3	Pilots: NWA: Omega Load Relief
A-12	B5.4.4	Pilots: NWA: Fisher Load Relief
A-12	B5.4.5	Pilots: NWA: Port Austin Load Relief
A-12	B5.4.6	Pilots: NWA: Veridian
A-12	B5.4.7	Pilots: NWA: EV Charging Demonstration at ACM
A-12	B5.4.9	Pilots: NWA: Adaptive Networked Microgrids

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A-19	I1.1	Telecom Reliability
A-19	I1.2	Telecom Cost

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I – Infrastructure Recovery Mechanism (IRM) Support

Part II – Grid Automation

A. Distribution Automation

B. Grid Automation Telecommunications

C. Conservation Voltage Reduction and Voltage/VAR (Volt-Amps Reactive) Optimization (CVR/VVO)

D. Non-Wire Alternative (NWA) Pilots

E. Grid Edge Insights and New Technology

F. Distribution Line Sensors

Part III – Operational Technology

G. Grid Management

H. Distribution Planning

I. Work Management and Scheduling

J. Asset Management

K. Mobile Technology

Q12. Can you please describe the Technology & Automation Pillar?

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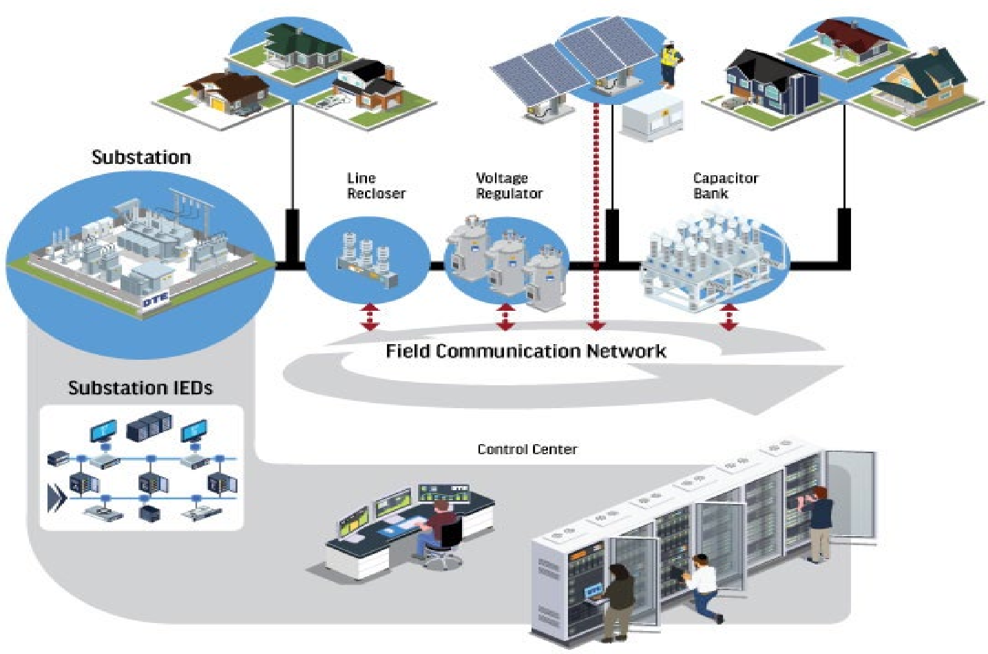
A12. Inherent to grid modernization, new technologies are becoming an increasingly fundamental part of the grid, improving the way modern electric grids operate and resulting in improved reliability, operability, and safety. Investments in technology also provide new opportunities to improve operations in ways that benefit customers, such as the ability to automatically isolate outages to limit the number of impacted customers. An additional critical function is to provide real-time visibility for system operators and engineers into circuit and substation loading. This loading data is critical to managing circuits efficiently both today and in the future, and to accommodating electric vehicles and increasing numbers of Distributed Energy Resources (DER) such as solar, and energy storage. A modern distribution system overview can be seen in the figure below.

Figure 1 Modern Distribution Overview



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Q13. What categories of investments make up the Technology and Automation Pillar?

A13. This pillar consists of the Grid Automation and Operational Technology categories. Grid Automation covers four key areas: Distribution Automation, Grid Automation Telecommunications, Conservation Voltage Reduction (CRV/VVO), and Non-Wire Alternatives (NWA) pilots. Operational Technology covers five key areas: Grid Management, Distribution Planning, Work Management and Scheduling, Asset Management, and Mobile Technology. These are discussed later in testimony.

Q14. Do Grid Automation and Operational Technology (OT) work independently of each other?

A14. No, OT is a set of enabling technologies that interact closely with Grid Automation and are tailored to support its objectives where needed within the Automaton roadmap.

<u>Infrastructure Recovery Mechanism (IRM) Support</u>

Q15. Are any of the programs you are supporting impacted by the Company's Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM)?

A15. Yes, as described by Company Witness Foley in his testimony, in the Commission's December 1, 2023 Order in Case No. U-21297 (December 2023 Order) it authorized IRM treatment for the 4.8 kV Circuit Automation program from December 1, 2023 through the end of 2025.

Line No.

Q16. Is the Company proposing recovery of any additional automation investment during the bridge and/or test years beyond what the Commission previously authorized for recovery through the IRM?

A16. Yes, as reflected in Exhibit A-12, Schedule B5.4, Page 17, Line 2, the Company is proposing recovery on an additional $21.2 million of Distribution Automation investment in 2024 and an additional $125.6 million of Distribution Automation investment in 2025. This investment is incremental to the automation investment already authorized for IRM treatment during these years and will support wholly different work to avoid double recovery of the same investment.

Q17. Is the Company proposing recovery for any additional automation investment through the IRM beyond the test year of this case?

A17. Yes, as described by Company Witness Foley, the Company is proposing a two-year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that extension the Company is proposing recovery of additional Distribution Automation capital investment as captured in Exhibit A-33, Schedule X1.

Q18. Is the Company proposing any modifications to the scope of the automation investment authorized for IRM treatment?

A18. Yes, as part of the proposed two-year IRM extension described by Company Witness Foley, the Company is proposing that the scope of the automation investment change from "4.8 kV Circuit Automation" to "Distribution Automation". This change reflects the Company's strategy to fully automate the distribution grid to provide safety and reliability benefits to customers. The is discussed in more detail in later in my testimony, questions 29 and 30.

Line No.

<u>Grid Automation</u>

Q19. What is Grid Automation?

A19. Grid Automation is focused on the physical technology infrastructure needed to support the efficient control and operation of a modern distribution grid. These investments include reclosers to improve safety and reliability, capacitors and voltage regulation for CVR/VVO, infrastructure to support NWA, DER, EVs, and grid telecommunications.

Q20. Why is investing in Grid Automation essential for the customers of DTEE?

A20. Grid Automation is essential for DTEE to improve grid reliability, provide an enhanced customer experience, facilitate grid planning, and support integration of DERs. The distribution grid is increasing in complexity as the result of growing bi-directional flow of power from the integration of renewable resources. Grid automation improves the reliability of the power grid by enabling real-time monitoring, control, and quick response to faults and abnormalities. It reduces outage durations, improves fault detection, and enhances grid resilience. Grid automation plays a crucial role in managing the variability and intermittency of renewable energy generation. It enables the ability to balance supply and demand, optimize energy flows, ensure grid stability, and facilitates the seamless integration of renewable energy into the grid. Grid Automation also provides valuable data and insights for grid planning and expansion. With automation, DTEE can adapt to changes in energy generation and consumption patterns, better accommodate the load growth from electric vehicles and integrate other new technologies into the grid. This flexibility ensures the grid can meet future energy demands and technological advancements.

Q21. Where are the details of the capital investment in this category?

A21. The details of the capital investment in this category are included in:

Exhibit A-12, Schedule B5.4, page 17-18

Exhibit A-23, Schedule M7

Table 1 Grid Automation Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Distribution Automation	p. 17, line 2	pp. 46-49	pp. 136, 138-139
Grid Automation Telecommunications	p. 17, line 6	pp. 74-77	pp. 136, 140-142
CVR/VVO	p. 17, line 8	pp. 34-37	pp. 136, 142
NWA: O'Shea Energy Storage	p. 17, line 9	pp. 142-145	pp. 136, 142-143
NWA: Battery Trailer	p. 17, line 10	pp. 125-128	pp. 136, 142-143
NWA: Omega Load Relief	p. 17, line 11	pp. 138-141	pp. 136, 142-143
NWA: Fisher Load Relief	p. 17, line 12	pp. 134-137	pp. 136, 142-143
NWA: Port Austin Load Relief	p. 17, line 13	pp. 146-149	pp. 136, 142-143
NWA: Veridian	p. 17, line 25	pp. 154-157	pp. 136, 142-143
EV Charging Projects	p. 17, line 28	pp. 129-133	pp. 136, 142-143
NWA: Adaptive Networked Microgrids	p. 17, line 26	pp. 120-124	pp. 136, 142-143
Grid Edge Insights & New Technology	p. 17, line 30	pp. 78-82	pp. 137, 143
DER Control	p. 18, line 31	pp. 38-41	pp. 137, 143
NWA: Small Solar and Storage Testbed	p. 17, line 14	pp. 150-153	pp. 137, 143
Sensor, Network and Algorithm Development (Solar Deployment)	p. 17, line 15	pp. 181-184	pp. 137, 143
Distribution Sensing and Monitoring (incldg Line Sensors)	p. 17, line 7	pp. 54-57	N/A

Line No.

A. Distribution Automation

Q22. What is Distribution Automation?

A22. Distribution Automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, monitor voltage and equipment health, and manage voltage and reactive power. Automation improves the speed, cost, and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers. This technology plays a crucial role in modernizing the power grid, as evidenced by The Department of Energy (DOE) report *Distribution Automation: Results from the Smart Grid Investment Grant Program*[1]," published in September 2016.

Q23. What are the benefits of Distribution Automation?

A23. The benefits include: improved distribution system resilience to extreme weather which can limit the number of customer outages; improved Fault Location, Isolation, and Service Restoration capabilities which improve customer restoration; more effective equipment monitoring and preventative maintenance to prevent equipment failures; more efficient use of repair crews; reduced repair times; and improved grid integration of DER.

The Distribution Automation technologies and Smart Grid Investment Grant Projects discussed by the DOE in a 2016 report on the benefits of distribution automation begin to quantify how these technologies can substantially benefit the grid. After deploying distribution automation programs, five utilities reported a 50-

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[1] Office of Electricity Delivery and Energy Reliability. (2016). *Distribution Automation: Results from the Smart Grid Investment Program*. U.S. Department of Energy. energy.gov/sites/prod/files/2017/01/f34/Final SGIG Report - 2016-12-20_clean.pdf

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55% reduction in the number of customer interruptions and customer minutes of interruptions per outage events, while three utilities reported System Average Interruption Frequency Index (SAIFI) improvements of 17-58% from pre-deployment baselines due to the ability to more quickly identify the location of a fault and perform switching activities that allow the fault to be isolated to a smaller area so that fewer customers are impacted during the repair activities. The real-world examples provided by the DOE in this study demonstrate that DTE Electric specific Distribution Automation circuit and program benefits, such as the SAIDI reduction of 54 minutes over 2024 and 2025, covered later are achievable.[2] (Distribution Automation: Results from the Smart Grid Investment Grant Program (energy.gov)).

Distribution Automation, which includes automated field devices, advanced protection, and SCADA, is a core component for grid modernization. Distribution Automation provides immediate system reliability benefits and adds the core components to support potential future grid needs.

Q24. What are the core investments the company is deploying to achieve these benefits?

A24. The Distribution Automation Program is primarily composed of pole top recloser deployments. Pole top reclosers, such as the G&W Electric's Viper recloser used in this program, offer a variety of capabilities needed for distribution automation such as the ability to isolate outages into smaller sections and the ability to reroute power around damage. Reclosers installed at midpoints on a circuit will operate

[2] See footnote 1.

when a fault is detected and isolate the outage to smaller area, impacting less customers. Reclosers installed at a tie point on the end of a circuit provide the ability to reconfigure circuits and reroute power around damaged sections by connecting to adjacent circuits. This device is also used to provide advanced protection capabilities, such as ground detection and isolation, which are covered in more detail in question 26. The pole top devices also provide circuit level SCADA monitoring and control to the System Operations Center. Beyond the pole top reclosers, some general distribution construction may be needed to create tie points on distribution circuits and to support capacity and voltage during reconfiguration.

Q25. Does DTEE have any unique considerations informing the development of its Distribution Automation strategy?

A25. DTEE has two unique considerations that were important when evaluating Distribution Automation on the Company's distribution system. The first of these is the nature of the ungrounded 4.8 kV delta system. This consideration is unique as most utilities no longer have this type of lower voltage ungrounded system to consider. Distribution Automation will improve ground detection and isolation, thus reducing the risk of energized down wire on the ungrounded 4.8 kV system. The ground detection functionality adds improved safety factors to the traditional reliability improvement from Distribution Automation. The second consideration is that service restoration benefits identified in Distribution Automation require a level of circuit connectivity and capacity beyond what DTEE has in some areas of the distribution grid. Circuits with existing connections that need only automation equipment installed will be targeted earlier in this process, while circuits requiring new connectivity or additional capacity are prioritized later in order to maximize near term benefits for customers.

Q26. What benefits can reclosers provide in terms of ground detection and isolation?

A26. A ground on a circuit is a potential indicator of an energized wire-down condition that in some circumstances could pose a safety hazard to the public. The Distribution Automation Program includes start of circuit reclosers that provide new capability to detect when a ground occurs on a circuit as well as the ability to isolate the grounded circuit. Currently, when a ground alarm appears on a circuit, a substation operator is dispatched to the substation and manually identifies which circuit has a ground, then a field crew is sent to locate the ground and isolate. With the ability to automatically identify this condition, the hazard can be detected and deenergized much more quickly and efficiently through automated isolation, quickly eliminating the risk associated with the downed wire. Addressing these hazards automatically not only reduces the safety risk sooner but allows resources previously used to isolate energized wire downs to be directed to restoration activities. This grid improvement is accomplished by installing start of circuit reclosers across all circuits fed from the same substation transformer and programming these reclosers using timing coordination between the circuits. Under this structure, when a ground occurs on one of the circuits from that substation transformer, all of the circuits detect the ground. This trigger programmed timing coordination of the reclosers, where each recloser operates in sequence until the circuit with the ground is detected and isolates that individual circuit. As a result, potentially energized wire downs are isolated and deenergized

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very quickly. These benefits will apply to all circuits being automated in 2024 (95 circuits), which currently see an average of 16 downed wires per year, and to the 149 4.8 kV circuits being automated in 2025, which currently see an average of 17 downed wires per year.

Q27. Are the technology investments for the Distribution Automation Program the same for all circuits?

A27. No. To achieve the service restoration capabilities associated with FLISR, an alternative source of power from adjacent circuits with capacity for additional load needs to be available. Approximately half (48%) of DTEE's distribution circuits already have these connection points established and have the ability to provide sufficient capacity to allow service restoration during an outage event. An additional 40% of circuits either require some investment to establish connection points or require detailed evaluation to determine if investment is needed to increase emergency capacity needed to support service restoration. The remaining 12% of circuits have physical restrictions such as lakes, rivers, freeways, or service territory boundaries that may make establishing connections with adjacent circuits difficult. The estimated benefits of tie locations are also adjusted to account for catastrophic storm conditions during which both circuits may be impacted, thereby reducing the benefits. This condition is addressed through a reduction to overall benefits of the Distribution Automation Program rather than on an individual circuit basis.

Q28. What factors inform the Company's prioritization for Distribution Automation?

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A28. Across Distribution Operations, the Global Prioritization Model (GPM) is used to rank strategic investments; this topic is described further by witness Kryscynski. These factors are what drives Distribution Automation's high GPM ranking: (a) the safety benefits associated with de-energizing down wires, (b) the reliability benefits associated with the reduced number of customer interruptions and the reduction of outage durations, and (c) the improved operational efficiencies associated with improved system monitoring and control. The safety benefit factor applies to all 4.8 kV circuits, and special weighting is given to the 4.8 kV circuits that have experienced high levels of wire downs. There are also additional safety benefits for completing all circuits associated with a particular substation transformer to ensure ground isolation coordination. Reliability benefits are estimated at the individual circuit level based on historical reliability and the existing level of automation. The existing level of automation is also key to estimating costs for cost/benefit circuit prioritization. Operational efficiency improvements are universally applied with improvements in safety and reliability.

Q29. What is the Company's scope for Distribution Automation?

A29. The scope of Distribution Automation includes: (a) installation of SCADA enabled reclosers on larger circuits with more than 400 customers to have at a minimum of one midline recloser and a SCADA enabled tie point, (b) installation of a recloser near the start of the overhead portion of a circuit for all ungrounded 4.8 kV circuits to enable ground detection and isolation, (c) installation of reclosers near the start of the circuit on 13.2 kV circuits that currently do not have SCADA enabled circuit breakers in the substation, (d) the construction of the necessary overhead equipment to create and enable load shifts between circuits, and, (e) the integration of devices

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and technology within ADMS to allow for the application of FLISR with the new and existing devices. The scope will also include ground fault detection and isolation on the 4.8 kV system, SCADA monitoring and control of all general-purpose distribution circuits, and improved fault isolation and increased remote restoration capabilities to improve reliability.

Q30. How has this strategy evolved since the Company's previous rate case, Case No. U-21297, was filed?

A30. Following the severe storms that impacted the Company's service territory in early 2023, a review of the outage events and the duration of restoration concluded that the limited deployment of automation across the electric grid was impeding the Company's ability to restore services to customers swiftly during large storm events. Based on this conclusion, the Company determined that extensive circuit automation was required to improve reliability performance for our customers.

As part of this expanded focus, the Distribution Automation Program was broadened to encompass the entire distribution grid, including the installation of SCADA-enabled reclosers and enabling remote sectionalization of outages into 400-800 customer segments. Additionally, it includes establishing tie points to connect circuits for efficient load shifting.

Furthermore, the Company recognized that deploying remotely operated SCADA-enabled reclosers on circuits will deliver most of the benefits associated with the substation automation program at a significantly accelerated pace. As a result of this assessment, funding for substation automation was reduced and redirected to

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Distribution Automation investments, which also supported greater alignment and bundling opportunity with substation related asset replacement scope of work.

Q31. With the expanded scope of Distribution Automation and the refined ability to prioritize circuits to automate, will the Company combine 4.8 kV circuit automation, 13.2 kV circuit automation, substation automation, and circuit rebuild for automation into a single focused distribution automation program?

A31. Yes. The Company has developed a cost-benefit model for Distribution Automation that estimates the reliability and safety impact and the investment required for every distribution circuit. This model allows the Company to prioritize circuits across all of the previously individual automation programs. As a fundamental step in the program, standards are being developed for the implementation of automation associated with specific grid voltage. Investment for recloser installations in 2024 will continue to focus on the 4.8 kV distribution system, based on standards and design work that was completed in 2023. The 13.2 kV standards for automation are being developed in 2024, which will ensure the 2024 design and 2025 construction will be aligned with the updated circuit prioritization model.

Q32. How are circuit level benefits estimated?

A32. Distribution Automation circuit level benefits were modelled by reviewing historical reliability performance against expected performance based on installation of Distribution Automation equipment including midpoint reclosers and SCADA enabled tie points. For example, a 4.8 kV circuit without any automation

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would have been modeled by reviewing the reliability data for the recent outages and then reviewing what the reliability data would have been after the planned installation start of circuit ground detection recloser, a midpoint recloser and a tie recloser. The operational efficiency benefits provided by automation were estimated and applied to those outages as well as modelled reductions in customers interrupted and outage durations. These reductions were modelled based on automation design requirements and are consistent with the industry performance improvement data seen in the DOE Smart Grid Investment Grant Projects paper discussed earlier. Benefits were not included in this analysis for circuits where automation already exists. The individual circuit costs were estimated by reviewing existing circuit automation and then defining the expected additional equipment needed to achieve the modelled benefits.

Q33. What is the scope of the Distribution Automation Plan for 2024 and 2025?

A33. The 2024 Distribution Automation Plan is composed of the investments included in the IRM in Case No. U-21297, which is 63 circuits and 189 reclosers, plus an additional 96 reclosers that are expected to improve 32 circuits on the 4.8 kV distribution system. In addition, engineering and design work will be completed in 2024 for 240 reclosers covering approximately 80 circuits to be constructed in 2025. In 2025, 578 reclosers across an estimated 242 circuits will be constructed based on the prioritization model developed in 2023 and 480 reclosers and 160 circuits are expected to undergo engineering and design in 2025 for 2026 construction.

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Q34. What benefits are associated with the Distribution Automation investments planned for 2024 to 2025?

A34. The planned Distribution Automation work for 2024 is expected to address ground detection and isolation for 63 circuits at 18 substations that is part of the IRM, and an additional 32 circuits at 11 substations. It is also expected to reduce SAIDI on impacted circuits by 45%, reducing system SAIDI by 9 minutes, based on the circuit level benefits modeling discussed earlier. The planned work for 2025 is expected to address ground detection and isolation for 281 circuits at 73 substations and is expected to reduce SAIDI on impacted circuits by 47% reducing system SAIDI by 45 minutes.

Q35. What progress in Distribution Automation was made in 2023?

A35. In 2023, DTEE completed engineering and design standards for use of the Distribution Automation reclosers for 4.8 kV and initial standards for 4.8 kV ground detection and isolation, ground detection and isolation standards will be finalized in early 2024, based on incorporating process improvements identified during initial deployments. DTEE has field installed 208 reclosers and commissioned 102 more with fault isolation and remote operating capability, with the balance of 106 expected to be commissioned in early 2024. DTEE has also completed circuit level costs and benefits estimates, which will be used for circuit prioritization and program cost benefit estimation.

Q36. Has the Company been able to confirm the benefits of the 2023 Distribution Automation investments?

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A36. The majority of the 70 reclosers that were installed in 2023 were installed in the second half of the year so a full year of the performance data needed to confirm the estimated benefits is not yet available. DTEE will track performance in two ways to ensure expected benefits are achieved. First, in 2024, DTEE will begin using actual outage data to track estimated customer outage minutes saved by automation. This will ensure that automation is performing as expected during individual events. Second, DTEE will track the performance of Distribution Automation circuits before and after work is complete and will compare the change to the control group. Variance in individual circuit performance year to year can be heavily influence by weather and unique events, but comparing the performance of the larger group of automation circuits relative to the rest of the system can provide the validation of program level objectives.

B. Grid Automation Telecommunications

Q37. What is Grid Automation Telecommunications?

A37. Grid Automation Telecommunications refers to the use of telecommunications technology in the automation of electrical power grids. It involves the integration of communication systems with power distribution networks to enable real-time monitoring, control, and management of grid operations. The telecommunications network is the backbone system that connects the distribution automation equipment in the field to the ESOC, enabling two-way remote monitoring and control that provides visibility into grid conditions and allowing the ESOC to remotely operate grid devices. An advanced telecommunications infrastructure plays a crucial role in grid automation by providing reliable and secure communication channels for data exchange between various grid devices such as

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sensors, meters, switches, and control centers. Telecommunication networks have always played an important role in supporting the safe and reliable delivery of electric power. This role is becoming even more crucial in the looming industry transformation, since Smart Grid represents the convergence of telecommunications, computing, and energy technologies.

Q38. Can you describe the structure of a utility telecommunications network?

A38. A utility telecommunications network structure typically consists of various components that work together to facilitate communication and data exchange within the utility's infrastructure. Here are some key elements of an electric utility telecommunications network structure:

- Backhaul network: The backhaul network serves as the central communication backbone of the utility's infrastructure, connecting different sites, such as power plants, substations, and control centers. It handles high-capacity data transmission and supports critical applications, for monitoring, control and device management, and incorporates the highest level of cyber security controls and network management. Through 2025, the Company's Grid Automation Telecommunications investments are focused on expanding the backhaul network.
- The last mile network: The last mile network connects end-user devices, such as sensors, meters, and monitoring equipment, to the backhaul network. It enables data collecting, monitoring, and control and the edge of the network. It is made up of wireless technology such as microwave links, radio frequency (RF) networks, and cellular networks, to establish communication links between different sites. Wireless infrastructure provides flexibility and scalability in extending network coverage and provides a secure and manageable interface between devices and the

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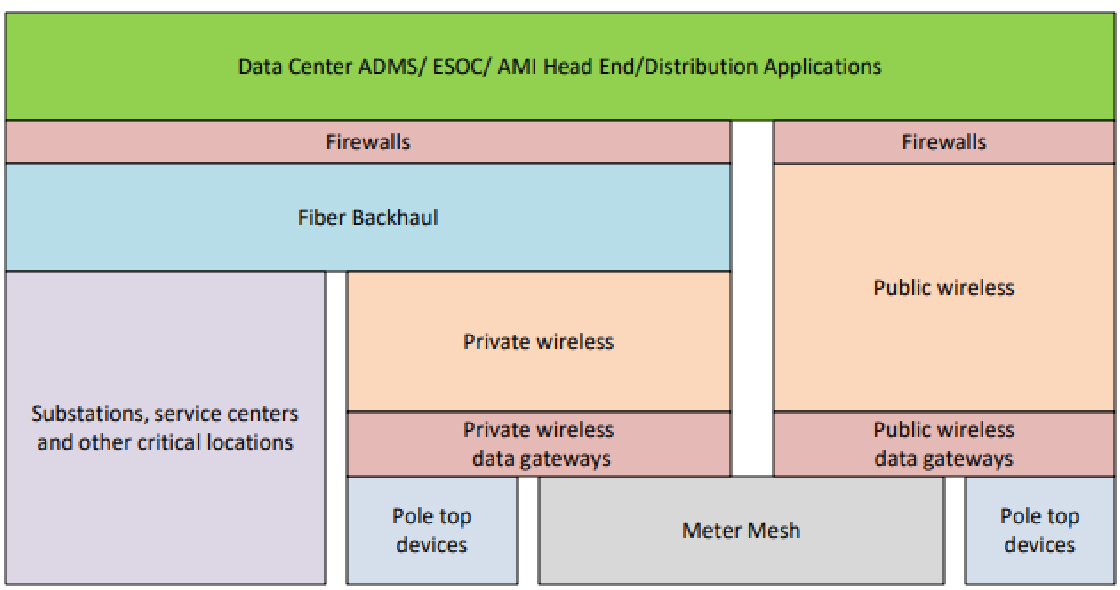
backhaul network. The Company is not making significant investments in this area for the time period of this instant case but plans to in the future.

The Grid telecommunications network consists of many technologies such as fiber, wireless systems, elevated structures, switches, and routers. Each of these technologies need supporting investment to create an integrated system that allows for the seamless flow of information, enabling remote monitoring and control of the grid and is the mechanism that cybersecurity threat monitoring and security updates are performed. See Figure 2 for a simplified structure of a Grid Telecommunications Network.

Figure 2 Simplified Structure of a Grid Telecommunications Network



Q39. Can you describe the existing state of the Company's Grid Automation Telecommunication network?

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A39. DTEE's existing telecommunication network consists of a combination of equipment and technologies including fiber, microwave, leased phone lines, and radio; some of these technologies being legacy end of life systems. The current network does not fully connect all field devices to the ESOC, many devices currently on the Company's electrical system, including some pole-top and substation equipment, are either not connected for remote monitoring and control, or are connected through a patchwork of communication networks and technologies that have varying capabilities, are not fully integrated, and in many cases cannot provide resiliency due to their architecture. At the center of the telecommunications system, the Company currently relies on a fiber ring that was originally designed to only connect data centers and transmission stations on towers along transmission corridors. The primary purpose of that connection was to provide a backhaul network enabling resiliency of data flow for critical operations. At the time the fiber ring was installed, the design scope did not include the capability for connecting the more modern distribution resources coming to the grid today, such as the circuit automation devices discussed earlier in this testimony. This portion of the backhaul network does not extend to all critical assets, which is why the Company is investing in expanding the backhaul network with additional fiber. Additionally, the legacy telecommunications technologies lack sufficient capability to provide the bandwidth speed, capability, and reliability necessary to stabilize delivery and response to the data being transmitted by those modern distribution resources and is a key driver of investment in Grid Automation Telecommunications.

Q40. What are the other key drivers of the Company's investment in Grid Automation Telecommunications?

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A40. The increasing deployment and utilization of grid automation equipment, evolving grid demands, and aging telecommunications infrastructure are the other key drivers of DTEE's investment in grid automation telecommunications.

First, in direct support of our distribution automation plan, the Company is increasing the deployment of Distribution Automation and smart devices in the field to drive improvements in grid reliability, resiliency, optimization, and efficiency through programs like Distribution Automation, Conservation Voltage Reduction (CVR), Volt-Var Optimization (VVO), Advanced Metering Infrastructure (AMI), and demand response. These technologies, when deployed on the grid, require real-time data transmission from field devices through a secure channel with sufficient, highly reliable bandwidth. Distribution automation alone plans to add over 13,000 new devices to the network which is over five times more distribution SCADA devices than are currently installed. As noted earlier in my testimony, DTEE is investing in automation devices that are being deployed on the grid to improve reliability. These devices require a telecommunications network that is reliable, secure, and has sufficient bandwidth to transmit data to allow for real-time monitoring and control. The investment in Grid Automation Telecommunications supports DTEE's Distribution Automation devices by providing the advancements in bandwidth, speed, capability, and reliability necessary to operate the modern grid and enable the benefits from the automation devices. These investments provide the necessary infrastructure and capabilities to automate and optimize grid operations and enhance reliability. Every alarm, command, and outage notification seen by the ADMS systems and System Operations Center (SOC) must come through the communications network.

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Without these investments, the Company would have to build device communication capacity as automation devices are installed on the grid.

Secondly, the increasing adoption of customer owned renewable energy sources is driving the need for integration and management of those sources to enable operators to monitor and control the flow of renewable energy. This control requires bidirectional information flow between utilities and renewable customers, and real-time communication that supports coordination and optimization of the electrical system. The Company's existing communications network was not designed to include the modern distribution resources coming to the grid, and the deployment of these resources requires additional bandwidth and reliable, quick transmission of data.

Lastly, some of the existing communications equipment is targeted for replacement due to obsolescence or lack of available spare parts. End of life, and legacy systems that are incapable of supporting new smart grid operations need to be replaced to support remote management of devices and to provide a platform to support the transition of existing communications assets.

Q41. What is the Company's investment plan for Grid Automation Telecommunications?

A41. DTE Electric's plan is to first expand the backhaul network fiber to provide sufficient bandwidth and high-speed data transmission capability, and then in future years outside of the timeframe of this case, to invest in the last-mile networks by

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connecting wireless systems to the fiber network to bring the visibility and control of all devices into the network.

The near term primary planned investment is expansion of the fiber system through the installation of a series of fiber rings that interconnect the Company's data centers with its distribution and sub transmission stations, service centers, communications towers, power plants, and other critical DTE Electric facilities. This system is designed to provide communications to locations where they are currently not deployed, have degraded service due to obsolete equipment, have incompatible networks and protocols, or are subject to interference or where the bandwidth needs have increased. The investments in the current case will address many of the critical infrastructure sites that can only be served with a fiber deployment.

The near-term investments in Grid Automation Telecommunications through 2025 will build out the critical backbone of the telecommunication network that connects the key infrastructure sites such as substations and other critical facilities to the various data centers. This is the foundational requirement to enable the functionality of the various operational technologies. Beyond 2025, DTE will need to continue to expand the telecommunication network investments to the next tier of locations that are prioritized from a resiliency perspective. Additionally, investments in 2026 and beyond will be structured to support an advanced wireless system that will be overlaid on the fiber backhaul to provide connectivity for pole top and distributed devices including mobile assets that will not be directly connected to fiber. This combined system of fiber and advanced wireless will

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provide sufficient capability to support the communications needs of the electrical system for decades to come.

This time staged deployment of telecommunications investments will provide reliable, high bandwidth, low latency backhaul for the Distribution Automation investments described earlier in this testimony, including SCADA, AMI backhaul data concentrators, asset monitoring sensors, physical security measures and future planned devices to provide control and visibility to the system control center and engineering backend systems.

Q42. How will customers benefit from the Company's investment in Grid Automation Telecommunications?

A42. Customers will gain significant benefits from the capabilities that Grid Automation Telecommunications will enable for Distribution Automation. Primarily, for the full reliability and operational benefits of Grid Automation investments described earlier in my testimony, including rapid fault location, isolation, and restoration to minimize downtime during outages and ensuring swift detection and response to disturbances on the grid. More details related to the benefits of fault location, isolation and service restoration are described later in the FLISR section of my testimony. Grid Automation Telecommunications will also provide sufficient future capacity as customers add new energy devices such as DER. Additionally, this solution will also improve coordination of DTEE resources by reducing the number of disparate and legacy systems that must be maintained and operated.

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Q43. What telecommunication options were considered in choosing the best technology investment to support Grid Automation Telecommunications backhaul network expansion?

A43. The Company employs multiple technologies in building the Grid Automation Telecommunications Network and all of them have an important place in the overall solution. We do not employ a one technology fits all strategy and for each portion of the network we consider all of the available technologies which include but are not limited to Microwave, Private mesh, Public commercial cellular, WiMAX, Private and public Fiber and private Radio. we even consider options that we have not yet invested in such as Private Cellular. All of these options were examined and in this case for this particular portion of the project and for this usage profile building our private Fiber capability was selected.

Multiple technology investment options were considered to support Grid Automation Telecommunications backhaul network expansion. The full implementation of communications to all end points will continue to utilize a variety of the available solutions where they are best suited to provide sufficient capability and reliability. Several factors were considered when selecting the backhaul technology to be utilized for the telecommunications, and a qualitative assessment of those factors is included here. The primary factors considered were the ability of the technology to fully serve the bandwidth (amount of data) and latency (delay in transmitting data) needs, and the reliability and the essential cybersecurity characteristics of those systems for providing service to critical sites and infrastructure. On a site-by-site basis, additional considerations for each of the technologies are factored into the decision of which technology to deploy.

Here is a summary of the uses and characteristics of each telecommunication system type evaluated:

<u>Public cellular:</u>

Description: Cellular technology owned and operated by a third-party telecommunications carrier and located on carrier owned cell phone towers or leased structures.

Current utilization:

- Short-term deployment where Distribution Automation is needed quickly, and other options are not currently available or cost effective.

Key Considerations:

- No quality of service guarantees for uptime or performance; carriers have already demonstrated they will not notify of network downtime including planned maintenance, or unplanned outages. Carrier maintenance, either planned or unplanned, can impact field network communications availability. When these outages occur, they can result in localized or wider ranging gaps service which impacts meter communications effectiveness. DTEE has no input into these outages and so finds it to be prudent to invest in multiple technologies to increase reliability. The timing of these service interruptions has impacts in large storm restoration when DTE is relying on meter information to establish which customers are restored to prioritize crew dispatch. Examples of reliability issues on this type of network are included in Exhibit A-19 Schedule I1.1.

- As a customer vs owner, DTEE is unable to configure specific routes between devices and set data prioritization policies for utility traffic. Prioritization of data relies on a vague tier system that prioritizes traffic with no guarantee or insight to analyze the network performance. No visibility into the network routing or ability to troubleshoot network connectivity or performance problems.
- Detailed cyber security logging and network traffic analysis is not available, requiring the layering of multiple levels of additional security on the traffic to encrypt the data which requires additional equipment infrastructure and configuration time and labor at each end point.
- Monthly fees are typically $25 per month per location and can exceed $175 per month for higher bandwidth plans. When considering the 40,000+ planned locations for automation and AMI backhaul that will be needed for Grid Automation the aggregate costs can reach into the hundreds of millions of dollars over the life span of the equipment and it is very likely that monthly costs will only increase as DTEE bandwidth needs increase and other carrier customers demand even more data. Sites that exceed bandwidth plans incur overage fees and in some cases the carriers' maximum plans are insufficient to support heavy bandwidth use cases like physical security cameras.
- Interference between other network tenants, in shared service areas at the edges of the DTEE territory or where municipal utilities have networks there are instances where interference has impacted network capabilities due to shared spectrum usage.

- Public carriers upgrade their system frequently, resulting in the removal of older hardware. This can cause premature obsolescence of functioning utility communications systems. This hardware replacement cycle is not in control of the utility and carrier changes in technology have been forced on the utility in some cases resulting in thousands of devices going out of support well before their end of life, or a complete lack of service. For example, prior to the 3G to 4G transition thousands of square miles of the service territory in the thumb region were suddenly without service as the networks were shut down and sold off because they were not seen as profitable in 2017. Overall, the 3G to 4G technology transition required DTEE to invest over $36M to reconfigure its network and reestablish communications to metering assets and device at over 2,700 locations, this does not include the cost of downtime, or the opportunity cost of applying that personnel time and investment to more valuable system enhancements. There was nothing wrong or obsolete about the 3G radios being used from a technical perspective (in some cases there were better propagation and range from the 3G equipment) and those devices could have had a substantially longer remaining lifetime before replacement if the network backhaul had not been subject to a technology change. These reconfigurations cause additional cost to troubleshoot communications failures, replace radios, conduct site evaluations to evaluate the replacement communication paths. This unplanned obsolescence is not a problem if the technology cycle was in control of the utility.
- Incapable of providing sufficient bandwidth for physical security use cases like security cameras.

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- In areas with sparse or no coverage it is at the carrier's discretion and the utility cost to install new infrastructure, meaning that these network extensions would have infrastructure buildout costs and additional lease costs above and beyond the monthly fees for data.

Private Long-Term Evolution (LTE) Cellular:

Description:

- Cellular equipment owned and operated by the Utility.

Current utilization:

- Not currently in use by the Company

Key Considerations:

- Best use as a last mile solution for distribution automation and DER
- Requires backhaul to get to data centers but can efficiently leverage the fiber investment.
- Requires investment in radio frequencies.

Point-to-Multipoint and Point-to-Point Microwave:

Current utilization:

- Used in spot solutions since it requires detailed pathing studies and communicates between specific locations.

Key Considerations:

- Existing issues with signal interference caused by new users of the frequency allowed by the deregulation of the frequency bands by the FCC, limiting the technological capability substantially and exposing the systems to excessive interference.

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- Microwave requires substantially more tower height that is more expensive and more difficult to site and permit to allow direct paths to function given the higher frequency's inability to penetrate tree cover.

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Wireless mesh:

Description:

- Utility owned radio equipment

Current or optional utilization:

- Supplementing the existing wireless mesh is a short-term solution being employed as part of the AMI program.
- The existing wireless mesh assets will be aligned to the fiber backhaul to improve overall system capability and resiliency.

Key Considerations:

- Does not address the backhaul bandwidth and routing issues with the system, or the requirements of grid automation.
- May be subject to public interference on shared frequencies and limited in power levels which reduces effective range, especially in heavily treed areas.

Leased fiber:

Description:

- Fiber lines owned and operated by a third-party vendor.

Current utilization:

- In specific locations where fiber is required for out of service territory wind parks, power plants, and facilities.

Key Considerations:

- Requires paying a telecom provider to build out the fiber network to provide the required point to point routes for distribution automation and then paying monthly lease and service fees in addition to the build out costs.

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- Requires negotiating and maintaining many contracts with different providers and negotiating to build fiber linkages between different vendors to complete the fiber rings needed for resiliency that may not be considered shared or beneficial routes by the provider, resulting in the Company absorbing the entire cost of construction.
- Where networks need to connect to provide resiliency, the Company must provide the risers, electronics, and routing equipment at these locations to ensure isolation of traffic and cyber security, resulting in increased infrastructure costs for this aspect of the project over a privately owned system that can optimize the locations of these installations and greatly simplify the equipment needed.
- While there may be minor cost savings where the providers have existing fiber lines, the Company's experience is that this is more costly by roughly 30% or more than building the fiber infrastructure efficiently on existing DTEE structures.

<u>Private, Company-owned fiber:</u>

Description:

- Fiber lines owned and operated by the Utility.

Current utilization:

- Existing fiber ring, and previous phases of grid automation telecommunications program

Key Considerations:

- Privately owned fiber allows for efficient and optimized routes, and infrastructure tailored to the utility use cases.

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Q44. Was a best investment option determined for this phase of the project?

A44. Yes, private fiber was determined to be the best investment for the 2024 and 2025 project scope for telecommunications backhaul. This does not mean that DTE will be using fiber exclusively for all telecommunications needs and different technology solutions will continue to be evaluated on a case by cases basis for specific locations. Fiber-optic networks offer unmatched bandwidth, speed, reliability, security, suitability for backhaul of other networks, and resilience to interference. Fiber-optic networks provide significantly higher data transmission speeds and bandwidth essential to support grid automation and scalability for the evolving demands of grid modernization initiatives.

For example, to meet the needs of substation physical security DTEE has already reached the maximum public cellular and pool data plans at some sites on public carriers, including FirstNet. The Company receives several notices a week that specific sites are using too much bandwidth; bandwidth easily provided by fiber and a factor in prioritizing the fiber deployment.

Fiber infrastructure provides the necessary backhaul for other communications networks, linking towers, base stations, and other access points to the core network. This connectivity is essential for carrying the massive volumes of data generated by devices to their intended destinations. Fiber infrastructure serves as the bedrock for all last mile networks, playing a pivotal role in ensuring their efficiency, speed, and reliability. Fiber-optic cables provide extremely high and consistent bandwidth over long distances compared to traditional copper cables or wireless medium, transmission capability crucial for the seamless functioning of networks. The

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inherent stability and low latency of fiber-optic connections ensure consistent and uninterrupted connectivity, indispensable to last mile networks. This reliability is vital for applications that require real-time data transmission, such as internet of things (IoT) devices, autonomous vehicles, and mission-critical communications. Without a robust and extensive fiber optic infrastructure, DTEE would struggle to deliver the high-speed, low-latency, and reliable connectivity demanded by today's digital landscape. Fiber serves as the linchpin that supports and sustains the interconnectedness and seamless operation of all connected technologies.

A group of internal SMEs discussed the different options and ranked them qualitatively based on several reliability, lifecycle, and initial cost factors. The results of the qualitative analysis can be seen below.

Figure 3 Alternatives Compared Using Reliability Factors

	Public Cellular	Private LTE	Microwave/ Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Bandwidth	◔	◑	◕	◑	●	●
Low Latency	◔	◕	◕	◑	●	●
Network Control	◔	●	●	●	◑	●
Prioritization and Quality of Service (QoS)	◔	●	●	●	◑	●
Security	◔	◕	◕	◑	◕	●
Maintenance Window Scheduling	○	●	●	●	◔	●
Disaster Recovery	◔	●	●	●	◑	●
Control of Communications During Emergency	◔	●	●	●	◑	●
Protection Against Interference and FCC Decisions	◔	◕	◔	◔	●	●

Figure 4 Alternatives Compared Using Life Cycle Factors

	Public Cellular	Private LTE	Microwave/ Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Ongoing Operating Costs (Excluding Staffing)	◔	◕	◕	◕	◔	●
Staffing	◕	◑	◔	◔	◕	◕
Open Standards	●	●	○	○	●	●
Technology Availability	◑	◕	◔	◔	●	●
Technology Stability	◑	●	◑	◑	●	●
Technology Lifespan	◑	◕	◑	◑	◕	●

Figure 5 Alternatives Compared Using Initial Cost Factors

	Public Cellular	Private LTE	Microwave/ Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Control of Geography Covered	◑	◕	◔	◑	◔	◕
Device Deployment Effort	●	◑	◔	◑	◕	◑
Installation Cost	◕	○	◔	◑	◕	○

Q45. How is fiber more resistant to interference?

A45. Fiber optic cable operates independently of the wireless spectrum, using light signals transmitted through glass fibers rather than the radio frequencies allocated and regulated by the Federal Communications Commission (FCC). This technology makes fiber impervious to the electromagnetic disruptions that affect wireless transmissions such as electromagnetic radiation, radio waves, electronic devices, and the FCC's spectrum reallocation, a process of redistributing portions of the electromagnetic spectrum for different services or technologies. Immunity to interference and FCC spectrum reallocation is a testament to the resilience and reliability of fiber optics among communication networks, ensuring consistent, high-quality data transmission and uninterrupted communication pathways critical for applications such as telecommunications, internet services, and utility-owned telecom systems. As a specific example, the Ann Arbor microwave was decommissioned and replaced with fiber after it was determined that a major wifi6 deployment would introduce substantial radio interference, rendering the microwave system unable to sustain reliable communications. Subsequent evaluation of the wireless traffic in the area indicated that this projection was accurate and that if the microwave had not been replaced with fiber it would have become unusable.

Q46. Why would the Company build a private network versus leasing from existing fiber providers?

A46. Owning and operating telecommunication systems allows greater control and flexibility over the networks. Unlike relying on leased or third-party systems, utility-owned infrastructure offers customization, scalability, and adaptability tailored to specific operational needs. This level of control is pivotal in integrating diverse technologies including sensors, IoT devices, and advanced monitoring tools essential for effective Distribution Automation and Smart Grid implementations.

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Utility-owned telecommunication systems provide enhanced security and resilience. By internalizing these systems, utilities can implement robust cybersecurity measures and ensure reliable communication channels, mitigating cybersecurity vulnerabilities associated with relying on external networks. Ownership of the network topology allows for efficient use of the entire network and eliminates constraints on traffic routing and prioritization. Investing in utility-owned telecommunication systems aligns with long-term cost-effectiveness and reduced recurring lease fees. Ownership reduces dependency on leased lines or external providers, minimizing ongoing operational expenses and providing greater predictability in maintenance and upgrades. Utility-owned telecommunication infrastructure represents a strategic move towards grid modernization and resilience. Lastly, a private network protects DTEE from network blackouts caused by using leased Internet Service Providers that do not build their networks with the same level of resilience that the electric grid requires. This has resulted in a strategic shift in recent years to build networks privately owned and maintained by DTEE to enable the Company to securely control and operate reliable telecommunication systems.

Q47. What components of the Grid Automation Telecommunications investment plan were completed in 2022 and 2023?

A47. Highlights of 2022 installations include:

- 220 miles completed.
- Fiber installations north and south of I-96 on the West side of Detroit and through Wayne County brought fiber to multiple service centers and backhaul towers, and substation locations.

- Installation and commissioning of a fiber route through Pontiac and adjacent areas north of the city.
- Significant work was started on the fiber line from Dearborn to Monroe and aligned with the telecommunications changes needed for the Trenton Channel Power plant decommissioning work.
- A major route was started to close a major gap in the existing fiber ring between M-53 in Macomb County and the Blue Water Energy Center.

2023 installations included:

- 239 miles completed.
- Completion and commissioning of the Dearborn to Monroe fiber line and the connection of both Fermi and Monroe power plant stations and facilities to the fiber network, including the Newport service center and substation locations.
- Substantial completion of routes on the East side of Detroit and up the I-94 corridor.
- Additional work nearing completion from 2023 are routes to reach Howell service center and the completion of the fiber ring from Monroe to Ann Arbor to provide resiliency to the Dearborn to Monroe line.

Q48. What investments are included in the 2024 and 2025 telecommunications investment plans?

A48. The major routes planned for completion in 2024 and 2025 are those in Detroit to serve all substations and communications towers. This work is being coordinated with the Infrastructure Resilience and Hardening Pilar as well as the City of Detroit Infrastructure (CODI) program.

2024:

- 150 miles in 2024 will provide a southern thumb ring running east to west north of I-69, and a route south of I-94 and Metro Airport to connect substations in the southwest region of the territory. The rest of the 2024 investment in fiber installation will be to install taps and entrances to substations from previously constructed routes.
- Installation of routing electronics to light up routes that have finished fiber construction and to connect substation end point taps with the existing wireless mesh network end points to improve bandwidth and reliability. This work will continue into 2025.

2025:

- Routes for 2025 will include investments to replace leased lines in the Eastern thumb and will be coordinated with sub transmission relocations. Additional routes in the City of Detroit will be constructed and coordinated with substation conversion and consolidation and the CODI program.
- 2025 will also focus on completion of critical infrastructure and resiliency routes and the electronics to connect the end point substations. The program will also begin to prepare for deployment of advanced wireless capabilities that will reach the tens of thousands of devices that are not economical to run fiber directly but will use the fiber as the high bandwidth and low latency backhaul to DTEE systems. These investments will verify that the communications industry marketing material contains accurate latency and bandwidth and appropriate prioritization of critical traffic based on carrier provided cellular build out versus an advanced wireless system supported by the fiber. This evaluation will investigate methods that may be more

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economically viable options to serve the end point devices that DTEE will be using to reduce customer outages and determining whether existing communications can support loop schemes and advanced protection to restore more of the population in a time period that does not cause disruption of service beyond a normal switching transient or other short-term events.

- A small portion of the 2025 investment is to validate last mile solutions in real world conditions and to document information and data received from the various methods of communications, allowing an investment and deployment plan for future years to be created. Testing will take into account factors such as the deployment of thousands of new DER (solar, storage, EVs) and bidirectional charging, all of which may need coordination with demand response events during times of summer and winter loading. The learning gained will also prepare DTEE to support upcoming Midcontinent Independent System Operator (MISO) rules for Federal Energy Regulatory Commission (FERC) Order 2222 and to fully support the new clean energy law. This work in 2025 will determine bandwidth, physical and cyber security requirements, and if a request for proposal (RFP) should be issued for additional communication services or infrastructure. It will determine if existing publicly or privately available communications are sufficient to provide reliability, latency, and bandwidth and to provide sufficient cyber security controls (which continue to increase in complexity and depth) to support grid modernization and increasing electrification.

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Q49. Can you describe what the Commission found in Case No. U-21297 about Grid Automation Telecommunications?

A49. The Order summarized the conclusions of the PFD stating "[t]he ALJ noted that DTE Electric expanded the scope of the program from the 500 miles of fiber and 230 substations proposed in Case No. U-20836 to the present proposal for 630 miles and 400 substations in the test year," then added that "[s]he [the ALJ] further found that the company should be required to provide an analysis of alternatives when requesting further extensions of the fiber network." (December 1, 2023 Order in Case No. U-21297, pg. 120). Earlier in my testimony I reviewed the options the Company has considered for expanding the fiber network, the rationale behind the Company's decision, and the description of the Company's planned investments in this area.

Below I address the concern regarding the change in scope proposed in Case No. U-21297 compared to the previous filing, Case No. U-20836.

Q50. What led to the change in scope from 500 miles of telecommunications fiber in Case No. U-20836 to 630 miles in Case No. U-21297?

A50. The 500 miles in Case No. U-20836 only included the scope of telecommunication fiber miles up through 2023 in testimony. Case No. U-21297 additionally included 2024 miles in testimony. The instant case also includes investment through 2025. Additionally, initial estimates of routes created at the engineering level have been updated for final route design, considering constructability, permitting, crossings, and accessibility of the path, which results in some routes being longer and some routes being shorter. Finally, the updated scope incorporated the additional fiber scope from other projects into the program. For example, the Trenton Channel Power Plant decommissioning required the relocation of the legacy communication infrastructure that was served from the plant. This additional scope had synergies with work that was already planned in the downriver area in the fiber program, resulted in a more robust solution and avoided duplicated work.

Q51. How is DTEE controlling the investment costs for this program?

A51. The Company is evaluating each route in the planning process to locate the most efficient path between stations, including competitively bidding the routes to multiple contractors that have demonstrated they can meet the installation standards. The selected contractors can perform the make ready work as well as the fiber stringing and splicing so it only requires one crew vs other approaches that would have to pair a line crew with a fiber crew or a 3rd party fiber crew with a line crew. The competitive bidding has been able to reduce the per mile cost on average by 35% and is expanded upon in Exhibit A-19 Schedule I1.2 A similar amount of savings has been seen compared to leased fiber construction routes, with the added benefit of avoiding the ongoing lease cost. Contractors have also identified additional savings on bulk purchasing material and scheduling work to minimize mobilization costs. This has allowed the program to maintain a design target of $55K per installed mile of fiber and, on average, consistently achieve that benchmark or better.

Q52. Will the investments in the Grid Automation Telecommunications Program continue past 2025?

A52. Yes, fiber installations are expected to continue into 2028. In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs. This is also being done to align construction of the fiber with sub transmission relocation to prevent installation of fiber in locations where the lines are planned to be moved, and to complete the installation of electronics and taps into substations. Future investments will also include the integration of an advanced wireless system to connect to additional device locations and assets inside the service territory. This proposed second phase of the grid telecommunications installation top address the last mile devices is projected to run through the end of the decade.

C. <u>Conservation Voltage Reduction and Volt-Var Optimization (CVR/VVO)</u>

Q53. What is Conservation Voltage Reduction and Volt-Var Optimization?

A53. Volt Var Optimization (VVO) manages system-wide reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing circuit level voltage, optimizing operating parameters and/or optimizing power factors, etc.

Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to maintain customer voltage down to the circuit level in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand and energy consumption.

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CVR is achieved by utilizing various electrical equipment including transformer load tap changers (LTC), overhead line regulators, and capacitor banks. In addition, supervisory control and data acquisition (SCADA) monitoring devices and line sensors are used to ensure customer voltage levels are maintained in allowable voltage ranges; advanced telecommunication and optimization tools can also be used to achieve optimal savings in the system.

Q54. What are the benefits and drivers of the CVR/VVO Program investments?

A54. CVR/VVO provides both a benefit to the distribution system as well as a generation alternative through reduced demand and energy consumption. Initial pilots conducted in 2020 through 2022 on six circuits using local control achieved peak reductions of 0.9% to 1.4% and energy savings of 0.7% to 1.0% and would be expected to raise to industry standard level 1.5% to 3% with the use of ADMS based CVR/VVO control. The CVR/VVO program is targeting a total peak demand reduction of up to 38 MW by 2030. In addition, CVR/VVO is, and will continue to be, a part of DTE Electric's integrated resource portfolio and are part of a utility system framework within the comprehensive context of an integrated resource planning process.

Q55. What work related to CVR/VVO has been completed to date?

A55. DTE Electric successfully enabled CVR/VVO technology on six pilot circuits in two substations on the distribution system in December 2020. CVR/VVO was enabled and measured throughout 2021 and produced demand and energy savings that were in line with the projections in DTE Electric's 2019 IRP filing (Case No. U-20471). CVR/VVO was enabled throughout 2022 and there have been no

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additional investments related to the pilot. The program was paused in 2022 and 2023 to align the program with advancements in ADMS that would allow for the use of ADMS CVR/VVO modules for control in place of the local electronic control used in the pilot. Although the program was paused, in 2023, engineering, design and the replacement of failed capacitors and capacitor controls with units that support CVR/VVO was completed.

Q56. What is the scope of work for the CVR/VVO Program for 2024 and 2025?

A56. In 2024, 22 circuits will be upgraded for $2.5 million. Circuit upgrades include the replacement of 36 capacitors and controls, four regulator control replacements, and the installation of 20 voltage monitoring locations. This work will allow for ADMS monitoring and control of voltage through CVR/VVO modules.

In 2025, 22 circuits are expected to be upgraded for $2.5 million. Circuit upgrades include the replacement of 40 capacitors and controls, two regulator control replacements, and the installation of 22 voltage monitoring locations. This work will allow for ADMS monitoring and control of voltage through CVR/VVO modules. In addition, the Company's scope of work includes a targeted capacitor control replacement program to address end of life capacitor controls that rely on time-based radio control. The existing radio controls have been determined to by obsolete by the manufacture and spare components for the radio transmitter are at risk of not being available. The capacitor control replacement program portion of the 2025 scope includes $5.6 million to replace 737 capacitor controls, bringing the total cost for 2025 to $8.1 million.

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Q57. How is the Capacitor Control Replacement Program related to CVR/VVO and what are the benefits?

A57. The Capacitor Replacement Program is a one-time investment to replace end of life and failed capacitor controls across the distribution system that could be utilized by CVR/VVO. The installations will be replacing the obsolete capacitor controls with the current standard control and installing sensing equipment that will allow for monitoring and remote control of the capacitor through SCADA and the ADMS. Replacing the existing capacitor controls with new SCADA enabled controls will allow for those units to be integration into CVR/VVO program. The capacitors replaced will be able to be controlled by the ADMS VVO module and provide real time optimization of the circuit voltage and reactive power. This will provide some efficiency benefit to the circuit related to improved power factor, but the circuits they are on will not have the voltage reduced to gain extra energy efficiency savings from CVR. Customers will also see the benefits of reduced losses from improved power factor and voltage management on the circuit.

D. <u>Non-Wire Alternatives (NWA) Pilots</u>

Q58. What are Non-Wire Alternatives?

A58. Non-Wire Alternatives (NWA), as initially defined by the Commission on page 11 of the August 20, 2020 Order in Case No. U-20147, are, "An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades."

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Q59. Why is the Company evaluating NWA?

A59. The August 20, 2020 Order in Case No. U-20147 ("August 2020 Order") stated on pages 43 and 44 that "the Commission expects to be presented with 'a robust suite of NWAs that may be evaluated for prudency as possible programs.'" Consistent with that Order, the Company developed a set of NWA pilots utilizing different technologies and addressing different grid concerns for inclusion in the 2021 DGP. Since 2018, DTE Electric has been implementing those NWA pilots using alternative technologies to address circuits or substations with loading concerns to help delay or offset traditional system upgrades. The Company plans to continue to implement the remaining pilots, as well as analyze the results of the completed pilots. This is also consistent with the industry's evaluation of the opportunities that NWA's present.

Q60. Did the Company present its NWA projects in its previous rate case?

A60. Yes, the Company proposed its NWA projects in Case No. U-21297. In its December 1, 2023 Order in that case the Commission approved the following projects: O'Shea (pg. 127); Omega (pg. 128); Mobile Battery Trailer (pg. 128); Fisher (pg. 129); Port Austin (pg. 128); and Veridian (pg. 130).

Q61. What is the Company's objective for NWA?

A61. The Company's objective is to incorporate NWA solutions into the distribution planning process to be considered along with traditional options to best meet the customer needs as described in the Company's 2023 DGP, Exhibit A23, Schedule M8, on pages 95 and 96. The pilots currently being pursued are building blocks that will form a foundation for future NWA projects. As capabilities are confirmed, multiple NWA technologies can be combined to further advance the Company's utilization of NWA.

Q62. What are the potential customer benefits of NWAs?

A62. NWA projects have the potential to become economic alternatives compared to traditional infrastructure upgrades. The pilots are expected to validate customer and economic benefits to help further refine the analysis of NWAs as an alternative to traditional solutions. While individual participating customers benefit from investment in some of the technologies used in targeted NWA solutions, such as lower energy bills due to EWR, customers overall may benefit from the deferred or displaced investment in infrastructure.

Q63. Can you please describe the NWA investments included in the instant case?

A63. The Company is currently engaged with a suite of nine NWA pilots. Some of the pilots are still under evaluation while others are in progress or have been completed. The NWA pilots are listed in Table 2 along with the use cases and technology the pilots are intended to test. The Hancock Pilot was completed and described in MPSC Case No. U-20836, and the remaining planned pilots are fully described in Exhibit A-12, Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-12, Schedule B.5.4.9 and Exhibit A-23, Schedule M7.

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Table 2 NWA Pilots Use Cases, Technologies, and Objectives

Use Case	Pilot	Technology							Objective
		EWR	DR	Storage	Solar	BTM DER	EV Charging	Microgrid	
Voltage Mitigation	1. O'Shea			✓					· Test effectiveness of storage to address voltage instability due to intermittent solar
Portable Battery	2. Mobile Battery Trailer			✓					· Test use of energy storage in place of traditional portable generators
Sub-transmission Loading	3. Omega			✓					· Deploy storage to address subtransmission loading · Install battery that can be re-located
Substation Loading	4. Hancock *(Completed)*	✓							· Initial pilot to test geo-targeted EWR and develop DER Estimating tool
	5. Fisher	✓	✓						· Test geo-targeted EWR/DR costs · Measure implementation timing
	6. Port Austin			✓	✓			✓	· Test solar and storage to address substation capacity · Test redeployment of stationary battery from Omega
Customer Load and DER Control	7. Veridian		✓	✓	✓	✓	✓	✓	· Develop secure and effective methods to interface and control behind the meter (BTM) DER in conjunction with utility scale DER
EV Charging	8. EV Demonstration at ACM						✓		· Develop control algorithms and conduct testing on an extreme fast charger and its interfaces as well as develop cyber secure smart charge management capabilities for Department of Energy
Reliability	9. Adaptive Networked Microgrids			✓	✓	✓		✓	· Develop and test the use of adaptive networked microgrids to improve customers' reliability and increase the benefits of NWA deployments

Q64. Can you elaborate on the technologies included in Table 2?

A64. Yes. EWR refers to replacing less efficient equipment with more efficient equipment, reducing overall electrical demand. DR refers to a shift or reduction in electricity usage by a utility customer to help manage demand on the electrical grid during periods of peak demand. Behind-the-Meter (BTM) refers to coordinating the participation of customer equipment to reduce overall demand or provide other system benefits. Electric Vehicle (EV) charging refers to coordinating the charging or discharging of EV equipment to provide electrical system benefits, avoid electrical system issues or address loading concerns.

Q65. Can you provide more detail on the Company's NWA pilot projects?

A65. Yes. Each pilot is described in detail in the following sections and Exhibit A-12, Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-12, Schedule B.5.4.9, and Exhibit A-23, Schedule M7 provide additional details.

<u>O'Shea</u>

Q66. Can you briefly describe the O'Shea Pilot?

A66. Yes. A 1 MW by 1 MWh Battery Energy Storage System (BESS) is being interconnected at the O'Shea Solar Park. O'Shea is a DTEE owned 2MW solar array installed on a circuit from the Chicago substation on the west side of Detroit to address power quality concerns related to the intermittent nature of the installed solar generation. The BESS is expected to address power quality for those customers.

Q67. What progress has been made for the O'Shea Pilot?

A67. DTEE has completed the below grade work at the site, poured concrete support pads, and installed the battery housing. The controls have been procured and are undergoing testing, and the site is ready for battery installation. The project has allowed the Company to create standard designs and to develop operation procedures, safety plans, and maintenance instructions. These learnings and the opportunity to test compliance to standards have resulted in the creation of safety policies for the installation and usage of battery systems that support not only this project but other storage projects in the future as well. The O'Shea Pilot has further allowed for the development of processes and practices for interconnecting battery systems at renewable sites.

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Q68. Does the O'Shea Pilot require any additional work?

A68. The tasks remaining are installing and commissioning the battery modules into the battery housing and then validating the control systems, communication infrastructure, new processes, standard designs, and other aspects of the pilot. The capability for the battery system to demonstrate participation in the wholesale market will be tested in consideration of FERC Order 841 to vet processes controls and communications that can be replicated at future battery sites.

<u>Mobile Battery Trailer</u>

Q69. Can you briefly describe the Mobile Battery Trailer Pilot Project including the customer benefits?

A69. Adding to the Company's mobile resources supporting geo-targeted major event restoration, DTE Electric has developed a mobile battery system that is capable of providing temporary power to a circuit and also supporting local system voltage. The mobile system consists of three separate trailers. Two trailers contain batteries (DC battery trailers), and the remaining trailer contains an inverter and system interconnection equipment (medium voltage trailer). The mobile battery systems have zero emissions and can support customer restorations in several ways including siting in place of traditional portable generators, supporting system requirements during shutdowns or maintenance, or being deployed at substations or on circuits to reduce peak load as part of a broader NWA project. The systems are designed to operate stand alone or in conjunction with other mobile resources.

Q70. What progress has been made in 2023?

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A70. The medium voltage and DC battery trailers have been delivered and connected at the DTEE Westland training center, where the solar and storage testbed is located, to allow for detailed checkouts of controls and onboard systems. Battery system communications, control functions and alarm screens were implemented on the trailers and run through testing. Initial documentation, procedural walkdowns, safety reviews, and testing of the house service and alarming systems were completed in 2023. Several modifications were identified and implemented to improve the deployment time and improve safety when operating the trailers.

Q71. What work is remaining for the Mobile Battery Trailer Pilot?

A71. Medium voltage testing will occur in early 2024 to validate the battery system control modes and communications with the System Control Center. These first tests will include validating functionality for the battery system including operator-controlled charging and discharging, peak shaving, volt var control, and solar smoothing as well as the onboard monitoring and safety systems. Procedures for disconnecting, moving, and reconnecting the battery systems will be field tested to allow for finalization of job units and work procedures. The systems will also be tested to work with other mobile resources and DER prior to deployment for support of the grid. During the testing, enhancements to functionality and control modes will be integrated into the Battery Trailer System(s) to increase the number of use cases the systems can support, and these enhancements will be propagated to the other Battery Trailer Systems.

<u>Omega</u>

Q72. Can you briefly describe the Omega Pilot Project?

A72. Yes. The Omega Pilot Project is located in the high growth area of Harrison Township. Two subtransmission lines feed Omega substation and both have been impeding further growth. In the near term, the placement of mobile storage equipment (the same type of equipment described in the Mobile Battery Trailer section) at the Omega substation will be used to reduce peak loading on the transformers and substransmission lines during contingencies, validating the ability of the mobile battery for peak load reduction and load shift use cases. The mobile batteries will be moved to other project locations, for example, Port Austin, once this capability demonstrated.

Q73. What work has been completed for the Omega Pilot?

A73. Engineering, design, and construction were completed for the site. Standards have also been developed to improve the efficiency of future applications of storage for the same purposes. The Company learned technical specifications and requirements to integrate battery storage equipment with the electrical system in a safe and reliable manner. The Battery Trailer Systems were delivered on site in Q4 2023 and connected to house service power.

Q74. What work is remaining for the Omega Pilot?

A74. Checkout and commissioning of the mobile battery systems is expected to be completed by end of Q2 2024. Upon completion, the controls and protection can be fully tested, and the medium voltage trailers can be connected to the distribution system. Additionally, the commissioning process and operational procedures in the control room and field for coordinating multiple battery systems at the same site will be established.

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Fisher

Q75. Can you briefly describe the Fisher Pilot?

A75. Yes. Fisher substation is located in Gibraltar and is over its firm capacity rating. In addition, two circuits served by Fisher are expected to be over the design standard. This poses significant risk of outages and inability to serve customers. The Company originally considered adding capacity at the substation by upgrading from a Class "F" substation to a Class "A"[3] substation, replacing existing substation transformers with larger transformers, installing a nine position Power Distribution Center (PDC[4]), and adding two new circuits to split the load. The Company then considered NWAs. The NWA scope includes targeted deployment of DR and EWR to relieve a portion of the load concerns. The remaining load concerns at Fisher will be addressed with the installation of an STDF (Subtransmission Distribution Facility[5]) in a 120kV corridor. This will allow one of the existing circuits to be split. The combination of energy waste reduction, demand response, and the STDF will address the loading concerns and return these circuits to their design capacity ratings.

Q76. What has been the progress and results of the EWR work at Fisher?

A76. The Company has been working on EWR in collaboration with the MPSC Staff and the Natural Resources Defense Council. The team continues to design and plan a cost-effective mix of pilot programs to deliver an estimated 300 peak-kW reduction

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[3] A class F is a small substation consists of two transformers and three breakers, while a Class A substation is more automated and has two or more transformers with each transformer having its own breaker

[4] A PDC is a power feed to a bus bar that supplies the individual circuits fed from a substation. It is similar in function to a breaker panel in a home at a much larger scale.

[5] A facility that consists of a set of equipment which creates a single circuit from a subtransmission connection.

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over the span of three years in the field. The pilots include geo-targeted bonus incentives to deliver off peak-load relief for premises connected to Fisher circuits. EWR progress for year-end 2023 is at a 139 peak-kW reduction.

Q77. What EWR work is still to be completed for the Fisher project and what is the expected timeline for that work?

A77. The field pilot programs will run for three years and are expected to be completed in 2025.

Q78. Are the EWR costs included in Exhibit A-12, Schedule B5.4?

A78. No. Energy Waste Reduction pilot costs are included as part of the Company's EWR Plan in Case No. U-20876, Exhibit A-11 and Exhibit A-14.

Q79. What has been the progress and results of the DR work at Fisher?

A79. As of Q4 2023, there is a cumulative total of 183 customers at the Fisher substation enrolled in the Smart Savers program; 57 new customer enrollments can be connected back to 2023 marketing initiatives. Based on a third-party forecasted analysis, these customers could each provide an average of 0.62 kW in load shed per event for a total of approximately 113 kW available in demand savings. As of Q4 2023, there are also a total of 298 CoolCurrents customers online and dispatchable at the Fisher substation. Based on the third-party forecasted analysis, these customers could each provide an average of 0.53 kW in load shed per event for a total of approximately 158 kW available in demand savings. In addition to the 298 online customers, the DR team has identified 201 CoolCurrents customers at the Fisher substation who are currently offline because they do not have a proper

24-volt power source connection. The Company has identified a solution for this and will be implementing it in 2024.

Q80. What DR work remains to be completed for the Fisher Pilot and what is the expected timeline for that work?

A80. The Fisher Pilot was launched in 2022 and is forecasted to run for three years until 2025. The DR team will continue to deploy enhanced marketing efforts for the Smart Savers program to drive incremental enrollment. The DR team will also continue efforts to restore offline CoolCurrents customers.

Q81. What has been the progress and next steps for the STDF?

A81. Preliminary engineering and design are completed. Reconductoring is expected to start in early 2024 and final construction is expected to be completed in 2024. The design for the STDF installation is forecasted to start in 2024, and the STDF will be installed and operational in 2024.

Port Austin

Q82. Can you briefly describe the Port Austin NWA Pilot?

A82. Yes. The Port Austin substation, located at the tip of the thumb, is over its firm rating, one circuit is over its day-to-day rating, and there are short periods of low voltage at the end of the circuits during periods of peak demand. The substation voltage is 4.8 kV, and the traditional method for addressing these concerns would be to convert the area to the higher 13.2 kV. However, significant load growth is not forecasted in this area, which makes this a lower priority for conversion compared to other areas. Additionally, this area is vulnerable to severe weather and experienced two tornadoes in recent years. With these considerations, the Company is piloting the application of solar generation combined with energy storage to address these concerns. Deployment of this equipment and using it to form a microgrid will benefit and supply power to a portion of the customers on the circuits if an event creates a fault that interrupts service from the substation.

Q83. What progress was made from 2022 through 2023?

A83. Engineering was completed for the Port Austin project in 2022 and detailed design was completed in early 2023. The purchase of the property was completed in 2023. Project construction permits were secured from Huron County in the fall of 2023. The solar equipment was purchased in 2022 and was delivered to DTEE in 2023. Site preparation and construction started in the fall of 2023.

Q84. What work remains for the Port Austin Pilot?

A84. Site construction needs to be completed and a mobile battery system will be delivered to the site. The control systems, communication infrastructure, new processes, standard designs, and other aspects of the pilot will be fully verified once the batteries and solar are installed, and the capability for the battery system to demonstrate participation in the wholesale market will be tested in consideration of FERC Order 841.

<u>Veridian</u>

Q85. Can you briefly describe the Veridian NWA Pilot?

A85. Veridian is a planned residential subdivision development in Ann Arbor made up of mixed use and community buildings and approximately 150 residential units that are a combination of detached single-family homes, townhomes and multi-unit dwellings. The area is served by the 4.8 kV Regent substation. While substation loading is not the primary concern, the overall load of the development is expected to approach 1.5 MVA, and none of the existing circuits have capacity to accommodate this level of load growth. However, the developer is planning to deploy customer owned solar and storage. By carefully coordinating the usage of the customer deployed DER with utility controls, system upgrades can be minimized yet still deliver the safe and reliable power required for this development. There are three aspects of the project: installing a URD loop, completing system upgrades, and developing a microgrid.

Q86. What work remains to be completed for the Veridian Pilot?

A86. Design is underway for the underground residential distribution (URD) and reconductoring portions of the Veridian project. The URD loop construction is currently scheduled to align with the developer's project plan, extending through early 2024. The system upgrade portion of the project began construction in 2023 and will be completed in 2024. The microgrid portion of this pilot is currently in detailed engineering study, and controls design, procurement, and construction will begin in 2024 and continue into 2025, aligning with occupancy of the development and the solar/storage DER components going on-line.

<u>EV Charging Demonstration at ACM</u>

Q87. Can you briefly describe the NWA: EV Charging Demonstration at ACM investment?

A87. This project includes investments in several different EV charging technologies and projects to learn how the various technologies will impact the grid. This includes the Department Of Energy (DOE) DE-EE0008361 Xtreme Fast Charging demo at ACM, the DOE VTO FOA-2197 EVs at RISC program, and the Electreon in-road charging pilot in Corktown sponsored by MDOT. The project scope also includes engineering support for transportation electrification including work with automotive OEMs and suppliers, engineering support and testing for managed charging pilots, engineering support for electric school buses, engineering support for Vehicle to Home (V2H) charging pilots, engineering support for Vehicle to Grid pilots (V2G), development of V2H and V2G interconnection requirements, charging interoperability testing and the distribution engineering support, testing and validation for many of the pilots initiated in the Emerging Technology Fund, which is described in Witness Pina Bennett's testimony at page 61.

Q88. Has the Commission addressed this project in a previous order?

A88. In its December 1, 2023 Order in Case No. U-21297 the Commission stated:

> The Commission notes that in the November 18 order, pp. 159-161, the Commission approved only 10% of the requested funding for this pilot. Based on the record in the instant case, the Commission is not persuaded to approve additional funding at this time. The Commission agrees with the Attorney General's assessment of the technology as currently so experimental as to be premature for funding by ratepayers. See, 6 Tr 3680-3681. Further, it is unclear what benefits—if any—would be available to DTE Electric's customers other than ACM, making it difficult to justify the reasonableness and prudence of having all customers pay for this pilot. (MPSC, p. 131)

Q89. Is the Company providing testimony to address the Commission's stated concerns?

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A89. Yes, additional support for cost recovery of this investment is provided to address the Commission's stated concerns. Furthermore, the historical project name is being kept for consistency even though the investments in EV technology programs addresses a broader scope of EV projects than the ACM Xtreme Fast Charging Project, and the ACM project component was completed in 2022.

Q90. Why were other EV project investments grouped with the NWA: EV Charging Demonstration Pilot at ACM?

A90. Originally, when the project was created it supported multiple EV technology projects that were under consideration. The project that was furthest in development, (dating back to 2018) was the DE-EE0008361 Xtreme fast charging demo at ACM. The pilot's name was applied to the budget category even though it contained other EV projects, because at the time those other projects were still in initial stages and did not have any significant investment. The project name has been retained through subsequent cases for consistency even though it doesn't fully describe all the investments in the category. Table 3 provides a breakdown of the split between the ACM spend and that from other EV technology projects.

Table 3 Cost breakdown of ACM compared to total program

	2022	2023	2024	2025
ACM	$ 697,000	$ -	$ -	$ -
EV Programs	$ 595,000	$ 1,292,000	$ 920,000	$ 2,500,000
Program Total	$ 1,292,000	$ 1,292,000	$ 920,000	$ 2,500,000

Q91. What is included in Historical funding year for NWA: EV Charging Demonstration at ACM Pilot investment?

A91. At the ACM site, work included site preparation, below grade cable and conduit installation, foundations for equipment, installation of a medium voltage switch for isolation and operating, installation of relaying and power quality meter and communications and control hardware to measure and record data from charging events. The Xtreme fast charger successfully completed initial charging demonstrations in fall of 2022 and culminated in the demonstration to the Department of Energy on Oct 13, 2022[6].

For the other EV programs in this category, the work was primarily for the DOE VTO FOA-2197 EVs at RISC program[7] and focused on validating the data model and cyber security implementations necessary to provide managed charging in a multi stake holder environment where charging was dynamically controlled by grid conditions. This included an initial proof of concept demonstration to the Department of Energy of the system's ability to control vehicle charging locally and remotely based on real time grid conditions while implementing the required cybersecurity practices to maintain isolation of the utility control network. Additional work was performed on EV charging station protocol interoperability and compatibility for managed charging and demand response and initial investigations into the Electreon electric road technology and Vehicle to Grid functionality and standards.

[6] High-Efficiency, Medium-Voltage-Input, Solid-State-Transformer-Based 400-kW/1000V/400A Extreme Fast Charger for Electric Vehicles (Technical Report) | OSTI.GOV available at https://www.osti.gov/biblio/1987553

[7] EVs-at-RISC: A Secure and Resilient Interoperable Smart Charge Management Control System Architecture for Electric Vehicles At-Scale : elt265 (energy.gov) available at https://www.energy.gov/sites/default/files/2021-07/elt265_woodbury_2021_o_5-14_500pm_KF_ML.pdf

Q92. What investments are included in the test and forecast year funding?

A92. A major portion of the investment during the test years is the technical demonstration of the DOE program for DE-FOA-0002197, EVS-at-RISC (Electric Vehicle Secure - Resilient Interoperable Smart Charging) This includes the initial and widescale demonstration of the system controlling multiple publicly accessible chargers in and around the Michigan central campus in Corktown. This demonstration will help the Company develop cyber-secure monitoring and control capabilities with smart charge controls to ensure reliable and secure interfaces to customer systems. The project will further enhance knowledge of the grid impact of these new management technologies. The electric Marketing organization has initiated Smart charge management projects that will be tested in multiple phases through 2023 and 2024 at the DTEE DER lab. Testing of vehicle protocol and interoperability will continue; especially as new commercially available systems integrate more directly with solar and storage and feature more complex controls and the ability to operate offline. Investments in the development of V2G and interconnections documentation will be completed in 2024 year. Engineering will also be done on the inductive road charging project to better understand the power quality impacts of wireless charging. Engineering support for Electric Vehicle Emerging Technology Fund (ETF) is primarily around providing feedback to the individual projects design. Work also includes supporting the implementation of testing of the solution and validating the technical performance of the projects.

Q93. Is there investment in the ACM portion of the project in the bridge years 2023 or 2024 or in the projected test year of 2025?

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A93. No, other than project close out and accounting, the specific work at ACM was completed in 2022 and the investments in this category are at sites other than ACM. DTEE continues to monitor the charger and solid-state transformer to gather additional data on charging events.

Q94. Can you describe the specific work for the NWA: EV Charging Demonstration at ACM?

A94. Yes, in addition to the information provided in Exhibit A-12, Schedule B5.4.7, the EV Charging Demo at ACM Project included DTE Electric supporting the implementation of the Delta Power Electronics DC Xtreme 400KW fast charger and solid state transformer installation as part of the DOE project DE-EE0008361/DE-FOA-0001808. The purpose of which was to gain understanding of the impacts of high-powered EV charging on power quality and operations. The pilot installed a power quality meter, utility gateway, and communications portal to (a) enable charge management, (b) develop control algorithms and conduct testing on a Delta Extreme fast charger and its interfaces, (c) develop cyber security interfaces and control, (d) install additional sensing capabilities, (e) monitor performance on the charging network, and (f) develop monitoring and control algorithms for in-road inductive charging at the ACM site. The DE-EE0008361 project began in 2018 with Delta being the prime recipient of funding to develop the extreme fast charger and associated solid state transformer, where most of the research and development work occurred at the Delta facility in Livonia. The project team members also included DTEE, General Motors (GM), Next Energy, Virginia Tech, the City of Detroit, and the Michigan Energy Office. This teaming is typical of DOE grant projects where a private technology partner teams with a university, national labs, and a utility partner to demonstrate a technology of interest to the Department of Energy. The project stated goals to the DOE were:

AREA OF INTEREST (AOI) 1: Extreme Fast Charging (XFC) Systems for Electric Vehicles:

- *To design and test a high-efficiency, medium-voltage-input, solid-state-transformer-based 400-kW Extreme Fast Charger (XFC) for electric vehicles, achieving better than 96.5 percent efficiency.*
- *To demonstrate extreme fast charging with a retrofitted General Motors' light-duty battery electric vehicle at 3C or higher charging rate for at least 50 percent increase of SOC.*
- *To achieve a 180-mile charge within 10 minutes.*

Stated benefits of the technology development were (a) a reduced amount of low voltage electrical equipment, (b) reduced charging losses, (c) the allowance of more direct integration of DER and storage into the system, (d) reduced space required for the unit, and (e) reduced labor to install high powered charging.

The initial Delta fast charger prototype was available by the end of 2020 and was tested electrically at the Next Energy microgrid. The second phase was field demonstration and installation which took place in late 2022 with a demonstration for the Department of Energy showing 400KW charging on commercially available vehicles and the use of a solid-state transformer.

The American Center for Mobility (ACM) demonstration was a collaboration between Delta, DTE Energy, and ACM. The ACM site draws directly from medium voltage 13.8 kV, which was already available at the station. ACM also provides a step towards "real-world" usage in a semi-controlled environment, as many ACM

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customers are running tests with electric vehicles where a fast charge will help them get back to testing quickly. The site constructed under the project closely mimics the process for fielding a medium voltage EV charger at other sites.

Q95. Is the charging technology demonstrated at ACM experimental and premature?

A95. No, the specific charger installed at ACM contained additional testing instrumentation and required more access for configuration than a final product. The ACM site charger, while not available commercially, has resulted in a commercial product that Delta is currently working to bring to market. The demonstration for the Department of Energy showed charging of 2023 model year vehicles, including a GM EV Hummer at full power of 400 KW and operating at the maximum of 800V, double the standard charging voltage in older EVs. This showed that the system could readily perform DC fast charging of a Ford F-150 Lightning, Chevy Bolt, and Cadillac Lyriq at their maximum charge rate as well. All these vehicles were standard production and unmodified. This technology demonstration is fundamental to encouraging rapid electrification and improving the charging experience for EV owners by reducing the charging time for a full charge from multiple hours to just minutes. This project demonstration identified best practices that can be applied to any similar high powered future charging projects that would result in reduced design and construction costs and allow for the early identification of potential roadblocks to installation. The scope of evaluation with the Department of Energy is to demonstrate technical feasibility and meet demonstration milestones. The Department of Energy Vehicle

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Technology Office has clear criteria to facilitate the commercialization of technologies demonstrated.

Q96. Does the ACM project show a successful approach to leveraging other funding sources to innovate and support electrification?

A96. Yes. Delta, the primary recipient of the grant, funded development of the solid-state transformer and extreme fast charging system and provided the equipment to the project. The Company fulfilled the role of the host utility to provide engineering input into the project to reach a successful integration of the grid connection and engineering and operating support. ACM acted as the site host for the demonstration primarily because initial testing required vehicles that were heavily modified to accept the high-powered charging and these vehicles were not certified to drive on the open road thus requiring a test track location. Without the initial testing on the closed track, there was no way to rapidly discharge the vehicle batteries to perform cycle testing on the system to validate that the power management and thermal management of both the vehicle and the charger was performing as expected. For the final demonstrations, the test vehicles were replaced with production models as GM had integrated the technology into their core drivetrain platform by that time.

Q97. What benefits did the ACM Pilot have that can be applied beyond the ACM site?

A97. By participating in Department of Energy projects that include equipment manufacturers and research institutions, DTEE is able to obtain valuable information on technologies such as extreme fast charging as well as on solid-state transformer technology performance. DTEE also supported Delta in developing a product that would allow high power charging to be deployed more cost effectively in the future by eliminating equipment and construction costs for unnecessary secondary voltage equipment and transformation. Additionally, DTEE evaluated the method needed for grid connection and operation at high powered charging sites that will not have on site trained electrical staff like an industrial facility might have. The demonstration also provided experience with solid state transformer technology where the EV charger direct current is directly coupled to the medium voltage primary system, allowing for higher charging rates and significant efficiency gains by eliminating traditional transformation and secondary voltage wiring.

Q98. What benefits do the other EV charging investments beyond the ACM Pilot have for customers?

A98. As EV's become more prevalent in the Company's service territory, the learnings from these projects will support a more efficient incorporation into the grid, laying the groundwork for EV's to be a grid-benefitting resource. There are three major benefits for the additional investments.

- Create a consistent and clear set of standards and requirements for the connection and operation of Vehicle to Home (V2H) and Vehicle to Grid (V2G) technologies and to use these as the baseline for necessary changes in processes and organizations that directly interface with the customer that is requesting those capabilities to streamline that experience.

- Define and implement the appropriate communication, cybersecurity, and control architectures for managed charging to allow for greater adoption of EV charging and minimizing the impact of grid constraints.
- Increase insight into the benefits of managed charging and the impact of EV charging on system loading and power quality, especially at high concentrations of charging to optimize circuit design and develop consistent methods for modelling the variability of managed charging and EV charging, this information will translate to projects that are better at integrating electrification.

Adaptive Networked Microgrids

Q99. Are there any additional pilots proposed based on the work at O'Shea and Port Austin?

A99. Yes. DTE Electric has been selected by the DOE for Infrastructure Investment and Jobs Act (IIJA) funding to expand on the Company's NWA work. Negotiations to finalize the project award expected to continue until sometime in the second quarter of 2024. DTE Electric will use this funding to grow the deployments at O'Shea Solar Park and Port Austin substation and to incorporate Adaptive Networked Microgrids (ANMs) to further increase the customer benefits from the deployed assets.

Q100. Why were these sites selected?

A100. DTE Electric is dedicated to the deployment of renewable NWA projects, and the ANMs will be an extension of that work. Both sites have assets already deployed that can be used in the networked microgrids. The NWA deployments for each were

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described earlier in my testimony, and by selecting these sites, the overall cost will be lower. Furthermore, Chicago substation / O'Shea is in an urban area with a high energy justice score, and Port Austin substation is in a rural area with longer circuits. Between these two locations, the ANM concept can be fully developed and tested for the benefits it provides customers in a range of settings. Additionally, both areas are served by 4.8 kV ungrounded delta circuits. When the reclosers are placed near the start of the circuit to detect and isolate grounds, the networked microgrids and fault location technology that will be developed during the project will further isolate the ground and continue to provide power to customers from outside the isolation area.

Q101. Why is the Company focused on microgrid development and deployment?

A101. The DOE's vision includes microgrids as a building block for the future electrical system[8]. Microgrids provide a mechanism to bring local DER together to provide solutions for resilience and reliability by becoming their natural aggregation point. Microgrids form a unit that hosts loads and generation that can be connected or disconnected from the rest of the grid. Additionally, multiple neighboring microgrids with dynamic boundaries can form larger multi-customer dynamic microgrids.

[8] *"By 2035, microgrids are envisioned to be essential building blocks of the future electricity delivery system to support resilience, decarbonization, and affordability. Microgrids will be increasingly important for integration and aggregation of high penetration distributed energy resources. Microgrids will accelerate the transformation toward a more distributed and flexible architecture in a socially equitable and secure manner."* from DOE OE 2021 Strategy White Papers on Microgrids: Microgrids as a Building Block for Future Grids – Topic 4, page 5, Available at https://www.energy.gov/sites/default/files/2022-12/Topic4%20Report.pdf, Accessed on November 28, 2023.

With that background, microgrids provide an opportunity to increase the benefits of the Company's NWA deployments and customers' DER installations. Deploying microgrids is directly aligned with the DOE's vision for the future electrical distribution system.

Q102. What are Adaptive Networked Microgrids (ANMs)?

A102. Adaptive Networked Microgrids are two or more neighboring microgrids with controls and protection that enable them to merge based on several considerations including but not limited to the locations of faults, load forecasts, weather forecasts, and DER status. These microgrids can dynamically change their boundaries through switching operations to isolate faults and improve the reliability of customers. This vision offers a chance to increase reliability, but development and testing are required.

Q103. What development and testing are needed?

A103. There are seven areas of focus for the development and testing leading up to the installations at O'Shea and Port Austin. This work is needed primarily to build on the Company's NWA pilots toward ANMs. The seven areas are Project and Technical Management, Sensors and Data Analytics, Cybersecurity, Control and Protection, Engineering Due Diligence, Microgrid Deployment, and Sharing Lessons Learned. Details on these seven areas can be found in Exhibit A-12, Schedule 5.4.9, Section 2(a).

Q104. How will the Company's customers benefit from this project?

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A104. Benefits to the Company's customers include (a) greater resilience to extreme weather conditions, (b) improved reliability for everyday operations, (c) enhanced security from an evolving number of cyber-physical threats, (d) superior flexibility to respond to the variability and uncertainty of conditions, and (e) increased sustainability through energy efficient and renewable resources. Additionally, the project will support the advancement of microgrids in general. Other technology, such as fault locating and state estimation will be developed from the project, that will benefit customers outside of the networked microgrid deployment. Overall, this will place Michigan as a leader in Adaptive Networked Microgrid technology.

Q105. Does the Company have any partners for this project?

A105. Yes. The Company has formed a partnership for this work called the Adaptive Networked Microgrid Partnership (ANMP). The Company's partners include Open Systems International (OSI), Open Energy Solutions (OES), Electric Power Research Institute (EPRI), and the University of Michigan-Dearborn. Lawrence Livermore National Laboratory (LLNL) and National Renewable Energy Laboratory (NREL) are advisors for the project. The roles of each partner are described in Exhibit A-12, Schedule B5.4.9.

Q106. Where will this new technology be deployed initially?

A106. After a period of development and testing at the Company's Solar and Storage Lab in Westland, Michigan, the deployments will be at Chicago substation/O'Shea Solar Park and Port Austin substation.

Q107. What specifically will be added at Chicago/O'Shea?

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A107. One of the batteries currently being used for the Omega Pilot will be transported to a new DER site to be installed on Chicago DC 1415 in the City of Detroit. Reclosers will be installed at the start of the circuit to isolate grounds, at each DER site, and on the circuit to isolate or connect the two DER sites to create dynamic microgrids.

Q108. What specifically will be completed at Port Austin?

A108. A DER site with a battery only will be installed adjacent to the microgrid currently being installed. Depending on equipment availability and cost, an additional DER site may be built next to the substation with solar and storage like the current DER being installed at Port Austin. Like the plan for Chicago/O'Shea, these DER sites will all be sectionalized by reclosers to dynamically shift the microgrid boundaries. There will also be sectionalizing at the beginning of the circuit for ground fault indication and isolation.

Q109. What are the expected costs for this work?

A109. The estimate for the pilot is approximately $46 million. This includes approximately $1 million in funding from the Company's partners, and $23 million from the DOE, which leaves approximately $22 million in funding from DTE Electric.

Q110. What is the schedule for this networked microgrid development work?

A110. The project is expected to progress over four phases that are roughly tied to the calendar years from 2024 to 2027. With the Engineering Phase primarily occurring in 2024, the Development Phase primarily occurring in 2025, the Deployment

Phase primarily occurring in 2026, and the Assessment Phase primarily occurring in 2027.

Q111. How is the funding provided by the DOE and the Company's partners included in the Exhibit A-12, Schedule B5.4?

A111. Line 26 on page 17 of Exhibit A-12, Schedule B5.4 provide the cost for the project. The funding from the DOE and the Company's partners to support the project is on line 27 on page 17 of Exhibit A-12, Schedule B5.4. Line 27 reduces the total cost of the project, which is included on Line 26.

Q112. What does the Order Case No. U-21297 include about Staff involvement for the NWA pilots?

A112. Page 124 of the December 1, 2023, Order in Case No. U-21297 includes the Staff's recommendation that "the company engage in ongoing consultation with the Staff and making other recommendations for the battery technology pilots and for ongoing updates that could ease the burden of litigating these pilots in rate cases." The Company has continued to involve Staff with NWA pilots. As an example, for the Adaptive Networked Microgrid, the Company presented the pilot to the Staff on November 14th, 2023, to ensure the Staff understands the concept and has an opportunity to offer their insights on the pilot.

E. <u>Grid Edge Insights and New Technology</u>

Q113. What is Grid Edge Insights and New Technology?

A113. This category of investments is a collection of projects that are designed to consolidate the learnings from the Non-Wire Alternatives projects into a consistent platform, and to unlock the capabilities of new equipment that is being brought to market to run the grid safer, more reliably and efficiently, ultimately increasing the amount of DER that can be accommodated on the grid. The projects that make up this category are summarized in the following table.

Table 4 Key Investment Highlights for Grid Edge Insights and New Technology

Key Investment	Use Case	Implementation Highlight
Grid Edge Insights	Consolidate capabilities developed in the NWA projects into a single modular platform to allow future NWA and DER installations to benefit from consistent technology, controls, communications and practices	Creation of a single interconnection gateway platform for all large interconnection and NWA projects. The platform will have a number of physical form factors to allow for deployment at small medium and large scale sites.
New Technology Evaluation	Test overhead, underground, substation and control equipment that is not currently in use at DTE to determine if it can be used to improve current operations. Create practices and procedures for the roll out of the technology into projects and programs.	All new equipment that will be operated and maintained by DTE Electric is run through the New Technology evaluation 6 gate process to ensure appropriate documentation, standards and procedures are created including installation at the Technical Training Center and field evaluations prior to broad deployment.
DER Control	Installation of standardized interconnection gateways at several DTE DER sites	Upgrades of controls and monitoring at Demille, Turril and Greenwood solar to improve remote management capabilities, integration with the control room and forecasting.
Small Solar and Storage Testbed	Testing hardware and capabilities to evaluate the performance and safety of commercially available solar and storage that customers are installing in the service territory and evaluate different configurations for interactions, safety and training for field crews.	Testing of customer DER configurations in a safe environment and enable the creation of practices and settings for smart inverter and microgrid functions for customers that install DER.
Sensor network and algorithm Development	Evaluate different remote sensing options to capture information that allows for improved forecasting and visibility into DER performance	Installation of weather network sensors and sky cameras to improve hourly forecasts of solar production in localized areas that have high solar penetration allowing the control to better understand fluctuations in loading.

Q114. What are the benefits of Grid Edge Insights and New Technology?

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A114. Evaluation and integration of new technology into the grid allows for technological enhancements to improve grid reliability, resilience, safety, efficiency, and opportunities for costs savings. The investments in Grid Edge Enablement will allow for additional NWA and DER resources to be connected into the grid in a safe and reliable manner by coordinating the DER controls with day-to-day grid operations. By having a consistent platform for integration, per project costs and time are reduced as site and controls design is limited to only those unique aspects of the DER that do not follow standard protocols and interoperability. Integration of Utility NWA and DER can be standardized, and interconnection of customer DER can be streamlined as substantial portions of the communication and control are pre-designed inside the gateway. The gateway allows for a consistent configuration, communications, and cybersecurity between the utility and the gateway and moves the complexity of dealing with site-by-site variation in hardware and implementation to the edge of the grid rather than having to accommodate the additional complexity in central IT systems like the ADMS and future Distributed Energy Resource Management System (DERMS). The modular nature of the gateway controls allows for expandability to accommodate new DER types, control algorithms, and functionalities and the system provides the ability for remote management and upgrades to reduce site visits.

Q115. What considerations inform the Company's strategy for Grid Edge Insights and New Technology?

A115. New technology is evaluated on several factors, with reliability and safety of the product taking precedence. The new technology process allows for a structured evaluation of all aspects of a product or functionality and for incorporation of

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lessons learned from other utilities, industries, and research organizations like EPRI. These lessons inform the determination of its readiness to be deployed into the grid. Careful attention is given to operating practices, worker safety, and the long-term sustainability of the product. Key aspects considered are the ability for the product and its controls to be integrated into the DTEE SCADA system and the cyber security of the product and its vendor support structure. This process allows for products and functionalities to be accepted and operating practices to be developed; it also provides the opportunity to identify any cross-cutting synergies in other areas where the same product or functionality can be reused to save costs. Other considerations include enabling additional capabilities for utility operations and customers to improve efficiency, reliability, and resilience. These factors can then be tested at the Technical Training Center which includes facilities for testing grid connected and the interactions of customer equipment at the Solar and Storage Testbed.

Q116. What is the Company's strategic scope for Grid Edge Insights and New Technology?

A116. Ongoing investments in this category are expected as the complexity of the grid and the capability of devices will continue to increase for decades to come as new technology is brought to the marketplace. A rigorous technology evaluation and selection program is instrumental in selecting the best technologies to construct the grid and to ensuring safe, reliable, and efficient operation for customers and employees. Investments in the introduction of new technology allow all projects and programs to benefit from improved performance and capabilities. For example, the pace of change of consumer DER products continues to increase and utility practices must keep up with customer expectations. As the industry adapts to these changes it is expected that there will be increased standardization in products and the need for increased communication between the customer and utility; this will drive additional requirements for interoperability and cyber security to unlock the full potential of DER and NWA and additional testing capability for the Solar and storage testbed to incorporate microgrid control functionality.

Q117. Were all capital investments in Grid Edge Enablement and New Technology described within the Distribution Automation financial exhibit?

A117. No. In 2022 and 2023, investment occurred under the OT program titled Interconnection Process Enablement. For 2024 this is described in The Operational Technology Distribution Planning section of this testimony. Investment for 2022 was $1.64 million and for 2023 $2.75 million, most of this being expansion of the small solar and storage testbed site to incorporate three phase 480V and medium voltage testing capability and gateway testing hardware. These investments were made under that category prior to the decision to split the DER controls and hardware from the backend OT functionalities needed for interconnection study and processing. For 2024 onward all the control and hardware investment will be included in the Grid Edge Enablement and New Technology Category. This work was not duplicative and simply represents a change in classification to align the projects more clearly to their focuses going forward. Work incorporated into the individual NWA projects reflects site specific implementations and while it is coordinated with the Grid Edge Enablement and new technology the investment is not duplicated between the projects.

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Q118. What progress has been made in 2022 and 2023?

A118. The solar and storage testbed has been expanded to allow for connection and testing of the interconnection gateways and battery trailer system. This expansion included test bays with medium voltage hookups, conduit, cable and switching equipment as well as communication and control wiring to allow for instrumentation and connection to the equipment.

The large interconnection gateway has been tested at the Solar Testbed and equipment is being prepared to be deployed to NWA projects such as O'Shea, and Port Austin. A variant has also been incorporated into the Battery Trailer systems. Grid edge functionalities for energy storage management and coordination between the utility control room and market operations were implemented into the gateway functionality along with safety and operating controls that allow for monitoring DER, energy storage systems, and alarms.

A Hardware-In-the-Loop (HIL) testing system has been installed in the testbed which allows for real time and repeatable testing of control and communications interactions of the actual grid control hardware while allowing for different circuit configurations and scenarios to be simulated. This functionality allows testing of complex control schemes leading to a high degree of confidence that the controls will work when deployed to the field. It also allows for rigorous testing of scenarios where changes in settings or conditions change; the tests can be rapidly rerun to verify that proper system operation will occur. This type of testing is critical to advanced functions such as microgrids where many devices must all operate together over different networks to allow for the successful transition of customers and resources onto and off the grid.

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Q119. What are the benefits of the 2022 and 2023 investments?

A119. Having a consistent design for the interconnection gateway allowed for NWA projects to incorporate the concrete pad, house service power, and communications requirements into the site plan with minimal design. The modular controls capability allowed each project to only focus on the unique aspect of the project design and use cases, significantly reducing engineering and design time and eliminating duplicated effort. The HIL system has already allowed for rapid verification of control concepts for NWA projects like the microgrid NWA at Port Austin.

Q120. What is the Company's plan for 2024 and 2025?

A120. Investments in 2024 and 2025 include integrations into the interconnection gateway of functionalities for microgrid operations, networked microgrid capabilities, coordination with grid automation, the inclusion of customer managed DER into grid optimization, EV and V2G management and Demand Response. Additionally, medium and small-scale gateway products will be evaluated and tested to allow more DER and NWA sites to benefit from the integrated gateway functionality. New technology evaluations will continue to expand the capabilities of grid automation to allow for more integration with ADMS FLISR, circuit loop schemes and distribution automation. Investment in gateways and sensor networks will establish a mechanism to replace the system loading visibility that is lost in no longer being able to install generation meters for specific customer classes. The testbed will also be enhanced to allow for the full training capabilities on customer DER configurations and testing of microgrid functionalities for NWA projects like the ANM using both the HIL simulation system and the testbed electrical network.

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Q121. What benefits are associated with the work planned for 2024 to 2025?

A121. New Technology evaluations in 2024 and 2025 will focus on supporting grid automation deployments and the various use cases for the viper reclosers and ADMS advanced functions such as CVR/VVO and FLISR. Additional standardization and practices for distribution connected energy storage and microgrids will be established. The investments in 2024 and 2025 will substantially increase the ability for the Company to integrate both utility and customer owned DER into grid operations and will streamline portions of the design and engineering for large customer interconnections. Optimization algorithms will be implemented to allow for more flexible DER operation and increased levels of DER and storage penetration into the distribution system. The HIL system and testbed will be utilized to validate that this new technology and functionality works together without creating unexpected operating behavior.

F. <u>Distribution Sensing and Monitoring (includg Line Sensors)</u>

Q122. What are Distribution Line Sensors?

A122. Distribution Line Sensors are devices used to monitor the real time status of the distribution system and provide critical information to field personnel and system control room operators to help them better monitor and manage the grid.

Q123. What is the scope of the Distribution Line Sensors Program?

A123. This program includes overhead system sensors used to monitor power quality and fault data needed for real time load transfer analysis, fault locating, and system status and Underground Residential Distribution (URD) sensors for use in underground area to quickly direct field crews to fault underground sections to improve isolation and restoration times. This program will also include a technology demonstration of new sensors intended to help monitor the system for broken pole and wire-downs, allowing dispatchers to better locate and differentiate between energized and deenergized wire-downs as well as down electrical lines versus joint use wires.

Q124. What are the benefits of Distribution Line Sensors?

A124. Distribution line sensors support faster outage restoration by helping to identify and locate faults, and dispatching crews to the identified fault location. Line sensors located at manual switches, crossings or other operating locations indicate to the control room that the fault has occurred beyond the device and a crew can be dispatched to the location, first to immediately restore portions of the circuit then to begin patrolling for the specific fault location from the line sensor location. Visual indication on the line sensors also helps crews quickly identify faulted lines when in the field. Many of the line sensors also collect loading and voltage data that can be sent directly to the ADMS and fault information that can be used in the ADMS advanced distribution applications like FLISR which contributes to reducing outage duration for customers. The line sensors work with the telecommunications system, described earlier in my testimony, to provide power and fault information to the ESOC and engineering personnel via the ADMS system.

Q125. What work was completed in 2023?

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A125. 398 underground (UG) line sensors and 100 overhead sensors were installed. Additionally, 300 pole sensors and 1000 overhead line sensors were purchased that will be installed in 2024.

Q126. What is the scope of work for the Distribution Line Sensors Program for 2024 and 2025?

A126. In 2024, 500 overhead line sensors will be installed, and 300 pole sensors will be installed and to test sensor ability to detect wire-downs. In 2025 the remaining overhead sensors and 1300 underground sensors will be installed.

<u>Operational Technology</u>

Q127. How does DTE Electric structure its distribution technology investments?

A127. Two primary areas make up the bulk of the DTE Electric distribution technology investments: Corporate Technology investments which make up the majority of traditional Information Technology (IT) assets, and Operational Technology (OT), those investments made specifically within a major operating unit, such as Distribution Operations.

DTEE's (2023) Distribution Grid Plan (DGP) covers technology investments specifically related to Grid Planning stating, "Implementing new information technology (IT) and operational technology (OT) will streamline and optimize the Company's planning while also improving safety and productivity. These investments form the core of the Technology and Automation Pillar." (Exhibit: A-23, Schedule M8, p. 129) The DGP forms the basis for a roadmap of technology investments categorized into five (5) areas: Grid Management, Distribution

Planning, Work Management and Scheduling, Asset Management, and Mobile Technology. These investment categories serve to organize individual investments and will be discussed in detail in this testimony.

This structure forms the underlying basis for planning and aligning the Company's technology investments over a 5+ year planning horizon and is the foundation for any updates or changes to this strategy as they represent the Company's technology investment.

Q128. How does planning for technology investments differ from the planning of more traditional equipment investments in the context of distribution grid planning?

A128. In navigating technology investments for distribution grid planning, it is crucial to recognize the shared planning aspects with traditional equipment investments. However, what sets technology investments apart are two key distinctions: the inherent dynamism, demanding adaptability due to rapid pace of technology change, and the ongoing deployed lifecycle, necessitating a nuanced strategy for balancing continuous optimization and evolution with prudent investment planning. Ongoing investments are necessary to address the changing technology landscape and take advantage of new functionality that delivers benefits to the customers.

- Rapid pace of technology change: Many capital investments like transformers, switchgear, and conductors have useful design lives that are measured in decades. These devices routinely spend their entire service lives without in-place updates or changes and usually do not need to be altered once deployed

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until they reach end of life. Technology assets are different . The services, features, and benefits provided by an asset often stem from its capability to adjust technology through remote programming or updating capabilities in place. It is that capability that delivers ongoing value to that asset yet makes planning for changes an asset may undergo over time a unique challenge. Technology asset change cycles are measured in months, quarters, or years, not in multiples of decades. Thus, the planned state for a system or technology can change rapidly, sometimes even over the course of initial deployment or shortly thereafter. This is an advantage rather than a weakness, but it challenges the concept that all these changes can be known prior to initially building and implementing these investments.

- Deployed lifecycle: The term deployed lifecycle refers to the various stages and processes involved in deploying a software application or system. Each phase, for example development, testing, deployment, monitoring, and maintenance, contributes to the overall lifecycle ensuring a smooth and effective deployment of software. Technology investments can have shorter deployed lifecycles than other grid assets. The Company invests in advancing technology, bringing it closer to customers as analog devices transition to digital. Examples of this are modern grid control devices like reclosers and meters, both of which have become computers in their own right. As more of the elements of those investments achieve greater sophistication in terms of computing responsibilities, the Company's need to protect them from the physical and cyber perspectives increases. Many of the field devices have and will continue to undergo rapid advances in capability. As the Company and customers demand faster and more capable service, they will need to be cycled

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in and out of service faster than their less capable predecessors. Just as there are very few 20-year-old computers in homes, so too will the Company's utility automation and technology investments need to be kept up to date more often than the strictly mechanical devices deployed in the past.

To be successful in technology planning the Company must stay abreast of evolving technologies, incorporate new functionalities, and address emerging challenges. Continuous investment allows for the integration of innovations that deliver value to customers, such as improved reliability, and better response to dynamic grid conditions.

Q129. Are there any additional differences to consider when planning for technology investments and the planning of more traditional equipment investments in the context of distribution grid planning?

A129. Yes. Other differences to consider include:

- External vulnerabilities: Any device placed into the grid infrastructure must be protected. Various devices in the electric grid require security measures, including Supervisory Control and Data Acquisition (SCADA) systems, routers, switches, smart meters, and communication networks. Protecting these devices is crucial to ensure the reliability and integrity of the grid. In the past, when devices were largely electro-mechanical, those security needs were primarily focused on preventing physical tampering and ensuring public safety. Today, when an advanced technological device is placed into service that need for protection goes beyond the physical, the company must now also prepare for cyber threats. Cyber threats are very real, and when they happen can be impactful and expensive. There is as much innovation and improvement going on in that arena as there is in the improvement of the technologies' actual purpose. As these threats gain sophistication, they can drastically affect the useful life of an investment. These threats may in some cases force the Company to modify or replace devices or systems prematurely when threats or methods unknown in the industry at installation emerge. Increased frequency of changes to address these threats are expected as indicated by the February 2024 testimony by the FBI and CISA (Critical Infrastructure Security Agency) to Congress[9] on the active attacks by foreign nation states on domestic critical infrastructure.

- Industry Advances: Many of this industry's traditional suppliers understand utility investment cycles and design products with those long replacement cycles in mind. Technology investments are very different in that the components, standards, devices, and methods cross multiple industries, minimizing the chance of supplier partners slowing the pace of their innovation or product improvements. This difference often directly impacts how often the company replans investments, as newer versions and capabilities overtake deployed solutions and require investment to keep pace.

These factors underscore the necessity for the Company to consistently review and adapt existing plans, occasionally expanding the scope of an investment shortly after, or even during, a technology deployment.

[9] Testimony of Dr. Charles Clancy available at https://www.congress.gov/118/meeting/house/116802/witnesses/HHRG-118-HM08-Wstate-ClancyC-20240206.pdf, accessed February 22, 2024

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Q130. How do the inherent differences in technology life cycles impact the timing of design requirements in a technology deployment?

A130. The inherent differences in technology life cycles can influence the timing of design requirements in a technology deployment by necessitating adjustments to align with evolving technology advancements and industry standards. Unlike standard capital investments with relatively stable design parameters, technology life cycles demand a heightened responsiveness to changing industry landscapes. This dynamic environment impacts the need for updates, adaptations, and new features. With solid practices and process and an agile and iterative approach to design, the Company ensures that technology remains effective and aligned with current standards throughout its deployment.

Q131. Does the Company ever change scope of OT projects in order to capture additional benefits?

A131. Yes. While the above questions pertain to all of OT planning, there are two specific areas contained in this testimony where scope was changed to achieve additional benefits. They are discussed below in Other Modernize Grid Management and Customer Power Status Visibility Project.

Q132. What are the major categories of Operational Technology investments?

A132. OT investments are aligned to five major categories:

- Grid Management
- Distribution Planning
- Work Management & Scheduling
- Asset Management

- Mobile Technology

G. Grid Management

Q133. What is Grid Management?

A133. Grid Management is a category of investments that enable the Company to monitor, control and optimize the operation of Grid Automation investments. These projects include the full suite of ADMS distribution management applications, including outage response, fault location, isolation, and service restoration (FLISR), and advanced control toolsets. Investments in this category enable distribution operators to model the real-time state of the electrical system and manage the entire distribution network. This includes systems that monitor and control the power system, manage planned and unplanned outages, and analyze and optimize the quality and reliability of the network. These investments also include the platforms that will enable the management of Distributed Energy Resources (DER) such as the DERMS (Distributed Energy Resource Management System).

Q134. What are the key drivers for the Grid Management investments?

A134. The key drivers for the Company's grid management investment include the need for:

- Cybersecurity: Investing in cybersecurity measures to protect against potential threats to the grid's infrastructure.
- Electrification: Supporting the growth of electric vehicles and other electrified technologies, which drives changes in grid capacity and management.
- Demand Response: Implementing strategies to match electricity consumption with supply to optimize grid performance.

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- Renewable Integration: Adapting the grid to incorporate renewable energy sources and manage their grid impacts and intermittent nature.
- Reliability and Resiliency: Ensuring both a stable and reliable power supply to meet increasing demand and reduce outages, while enhancing the grids' ability to withstand and recover from disruptions or cyber-attacks.

Collectively these key drivers create the need for grid management solutions.

Q135. Where are the capital investment details of the projects and programs in the Grid Management category?

A135. Capital investment details of these projects and programs in this category of the instant case can be found in:

- Exhibit A-12, Schedule B5.4, page 17-18
- Exhibit A-23, Schedule M7

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Table 5 Grid Management Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
SOC: ESOC	p. 17, line 4	pp. 189-192	pp. 145-150
SOC: ASOC	p. 17, line 5	pp. 185-188	pp. 145-150
ADMS: DMS/OMS	p. 17, line 3	pp. 8-11	pp. 145-150
Other Modernize Grid Management	p. 18, line 40	pp. 164-168	pp. 145-150
ADMS Enhancements	p. 18, line 32	pp. 4-7	pp. 145-150
Operational Technology and EFC	p. 18, line 33	pp. 158-163	pp. 145-150
Customer Power Status Visibility	p. 17, line 18	pp. 29-33	pp. 145-150
AMI: Meter Communications Upgrade	p. 17, line 17	pp. 17-20	pp. 145-150
Microwave End of Life	p. 18, line 39	pp. 104-107	pp. 145-150
FLISR Implementation	p. 18, line 35	pp. 70-73	pp. 145-150
DERMS	p. 18, line 36	pp. 42-45	pp. 145-150, 241-242
Substation Cybersecurity	p. 18, line 37	pp. 193-196	pp. 148, 243
Automation Configuration and Test Record Database	p. 18, line 38	pp. 25-28	pp. 148-149, 243
Meter Improvements	p. 18, line 34	pp. 100-103	pp. 145-150

System Operations Center (SOC) and Alternative System Operations Center (ASOC) Projects

Q136. What is the SOC Modernization Project?

A136. The SOC Modernization project replaced the Company's previous outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current security, resiliency, and operability standards. The two new facilities are called the Electric System Operations Center (ESOC), which was essentially completed and fully occupied as of February 2022, and the Alternate

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System Operations Center (ASOC) which certification will be complete in third quarter 2024. The previous SOC and backup SOC had significant limitations, which I will describe later in my testimony.

Q137. What are the essential functions of a SOC?

A137. The SOC is the most critical facility in Distribution Operations. Personnel in the SOC operate the subtransmission and distribution system in southeast Michigan, and additionally support generation operations. SOC System Supervisors are the ultimate authority for the DTE electrical system operation with the goal of maintaining safety of the field personnel and public, reliability of the electrical grid and the continuity of service to the customers. They monitor system conditions including alarms, and direct field personnel to safely operate electrical equipment for routine switching needed for maintenance, other planned activities, and for outage restoration. The SOC also coordinates with Electric Dispatch personnel to ensure appropriate crews are assigned to address system issues.

As a NERC registered Generator Operator (GOP) and Local Balancing Authority (LBA) the ESOC employees are also required to maintain the reliability and safety of the Bulk Electric System (BES) through coordination with the DTE Merchant Operations Center (MOC), and the Transmission Operator (ITC). Certified NERC operators in ESOC work closely with MISO, MOC, and the ITC to ensure system generation and load levels are kept in balance along with ensuring customer utilization voltage levels are maintained to prevent damage to customers equipment, ensure their critical processes operate as needed, and maintaining customer satisfaction with reliable power.

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Q138. Why was the SOC Modernization project needed to replace the previous SOC facility?

A138. The former SOC had several critical limitations, which DTE Electric identified through extensive benchmarking at the inception of this project. These critical limitations included DTE Electric's outdated facility with physical, manual visualization methods, end of life legacy technology that was no longer receiving necessary support and updates, space limitations to support future growth for critical reliability functions and limited visibility into the performance of supporting telecommunication infrastructure. The transformation from a manual state to a modern automated approach was imperative to address these challenges effectively.

Q139. What is the status of ESOC?

A139. ESOC integration has been successfully completed and integrated into full operations.

Q140. What is the ASOC?

A140. The ASOC will be the NERC required alternate backup redundant control center to the ESOC. Located inside the recently constructed Waterford Service Center it is comprised of approximately 16,300 square feet with back-up generation and double redundancy for wireless and internet capabilities. Construction on the Waterford Service Center in Waterford, Michigan, began in November 2022.

This facility will include electronic displays and software/hardware that meet dispatcher and operator needs and mimic the current ESOC standards. This will allow for a fully functioning, alternate location to carry-on the activities of the current Headquarters ESOC seamlessly, in the event of an emergency, as well as provide for the future training/re-training and testing of Electric System Operation Center employees.

Q141. With the completion of the new ESOC, is a new backup facility (ASOC) still needed?

A141. Yes. Without an alternate facility available in the event of a disruption at ESOC, recovering from a storm or other disaster would be extraordinarily challenging, and delay restoration. The reasons for building a new modernized backup facility have not changed since the Commission originally approved building a new ASOC in Case No. U-20561. Given the critical nature of the ESOC in operating the electric infrastructure, under any emergency conditions, a backup facility is required in the event the primary facility is inoperable. While the Company does utilize the current backup SOC on occasion, the facility is inadequate for sustained operations, and for disaster recovery efforts.

Q142. Has the MPSC ruled on the costs for the ASOC?

A142. Yes. On Page 119 of the December 1, 2023 Order in Case No. U-21297 the MPSC stated that "the Commission finds that the proposed ASOC spending is reasonable and prudent," and the amount requested by the Company was approved.

Q143. What is the status of the ASOC project?

A143. The construction portion of the ASOC buildout was completed in December of 2023, and completion of the technology build out of the space and interior

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construction will continue into the 2nd quarter of 2024. The ASOC is expected to achieve full NERC certification in 3rd quarter of 2024.

Q144. How will customers benefit from the total SOC Modernization project?

A144. Customers will benefit from the SOC Modernization project's two facilities (ESOC and ASOC) due to the improved communication paths between the resources that will be co-located in the new facilities. This will provide quicker and improved coordination to create and implement restoration strategies more effectively. In addition, customers will benefit from reduced risk of disruption in operations during outage events, and faster restoration times regardless of the facility from which the System Operations organization operates from. The ability to understand system conditions, and dispatch resources to address issues, will be greatly enhanced by the technology available in the new facilities and the co-location of the System Operators, Power Dispatchers, and support personnel. In addition, ESOC is more resilient and hardened to withstand adverse natural and man-made disasters, allowing electric grid operations to recover much more quickly in the event of a major catastrophe. These benefits have already started to materialize due to the utilization of the ESOC and will be fully realized once the ASOC is complete.

Advanced Distribution Management System (ADMS) Distribution Management System (DMS)/Outage Management System (OMS)

Q145. What is ADMS DMS/OMS?

A145. The Advanced Distribution Management System (ADMS) is a modern operating technology platform that is essential to the Company's grid modernization efforts which improves system reliability and operational efficiency. These software solutions are used to monitor, control, and optimize the distribution of electricity in real-time. ADMS combines Distribution Management System (DMS) and Outage Management System (OMS) functionalities to enhance the overall management of power distribution networks. The series of systems that comprise the ADMS platform represents a significant advance in the Company's situational awareness of grid condition, coordination of system operators and field personnel, and control of grid assets. It provides a consistent integrated view of the system to all organizations, supports faster restoration times, and allows for improved monitoring and control of the distribution system.

DMS is the Distribution Management System, which provides a complete network model of the electrical system for operators to view operating conditions in real time. DMS consists of multiple applications such as the Network Model (eMap), Distribution Power Flow (DPF), Distribution State Estimation (DSE), and applications with more advanced functionality such as Fault Location, Isolation, and Service Restoration (FLISR), Volt/Var Control (VVC), Conservation Voltage Reduction (CVR), Feeder Reconfiguration (FR), and electronic Switch Order Management (SOM).

OMS is the Outage Management System, which aggregates emergent trouble information reported by customers and AMI meters and allows system operators and dispatchers to prioritize response and properly assign crews for repairs, enhancing their ability to manage and minimize disruptions in service for customers.

Q146. Has the MPSC ruled on ADMS: DMS/OMS?

A146. Yes, on page 114 of its Order dated December 1, 2023 in Case No. U-21297, the Commission approved DTE Electric's requested expenditure for this component of ADMS, agreeing that outage restoration response is a critical area stating that, "the company took reasonable steps to address the problems with the DMS/OMS in light of the available options and approves DTE Electric's requested expenditure for inclusion in rate base."

Q147. What was the scope of work completed in 2023 for ADMS: DMS/OMS?

A147. DMS and OMS went live in February of 2023. Prior to go-live, the Company ran parallel operations for OMS where a subset of operations users used the new tool in parallel with the old tool to prepare for go-live. After go-live the Company moved into the hypercare phase of the project. Hypercare was an intense and focused phase of support and monitoring that immediately followed go-live. It involved round-the-clock support for system operations and field personnel as they became accustomed to operating the new systems. Additionally, EMS (Energy Management System), which is a software solution that allows for monitoring, control, and optimization of energy generation transmission, was upgraded at that same time to bring the existing EMS to a compatible version with OMS and DMS.

Q148. Given that DMS has gone live with OMS, have all DMS applications been operationalized?

A148. No. Although all DMS applications were deployed in February 2023, the Company will continue to build upon this foundation by implementing additional modules and enhancements throughout 2023 and beyond. At go-live, the eMap application and SCADA integration with OMS immediately enabled more accurate and timely outage event creation and situational awareness. Additional benefits will be realized as the Network Model is tuned and penetration of SCADA devices in the distribution grid increases. The investment to enable these remaining applications over the next 3-5 years is found in the ADMS Enhancements and FLISR Implementation line items in Exhibit A-12, Schedule B5.4, p.18, lines 32 and 35. More information on those applications and benefits can be found later in the ADMS Enhancements and FLISR Implementation sections of my testimony.

Other Modernize Grid Management

Q149. What is Other Modernize Grid Management?

A149. Other Modernize Grid Management is a category of investments that encompass a diverse set of projects designed to enhance the Company's operational capabilities, particularly during high-volume outage events, those that impact hundreds or thousands of customers. From software improvements to licensing acquisitions, each investment contributes uniquely to bolstering efficiency and resilience in the Company's technology landscape.

Q150. Were there any changes in this category of investment in 2023?

A150. Yes. The Company's achievement on February 6, 2023, with the launch of the comprehensive ADMS grid management set of tools marked a significant milestone. During the subsequent catastrophic ice storm, the Company leveraged the newly implemented system's breakthrough capabilities. Swiftly learning from this experience, the Company promptly initiated targeted projects to improve storm restoration and customer communications, integrating the lessons learned with the enhanced capabilities of the ADMS grid management tools. Early results showed the initiatives implemented resulted in immediate improvements to:

- Outage analysis processing, enabling faster event creation and initiating the restoration process for customers sooner.
- Momentary outage processing by improving the interfaces between ADMS and our AMI network.
- Faster outage restoration by leveraging improvements to bulk event updating and bulk crew assignment creation.

This highlights the system's adaptive response and its crucial role in optimizing storm resilience efforts.

Q151. What are the key investments in this category?

A151. The key investments in this category are:

- OSI Licensing
- Qlik 3-year license purchase
- CT/VT High voltage, and test accuracy console
- EFC Communications
- Purchase of backhaul capable field area routers
- Pre-Storm ADMS Enhancements
- Post-Storm ADMS Enhancements

Q152. Which projects in this category were initiated in 2023 to enhance storm restoration and communication efforts?

A152. The following projects were initiated to support storm restoration and customer communication efforts:

- Pre-Storm ADMS Enhancements
- Post-Storm ADMS Enhancements
- EFC Communications

Q153. What was the timing of the investment in these projects that were initiated to enhance storm restoration and communication efforts?

A153. These projects were swiftly initiated in 2023 in response to the severe storms and new ADMS enabled technology to make improvements. These projects, crucial to supporting storm restoration and communication, will continue in 2024 and beyond. Future investments into these projects are listed in separate line items in Exhibit A-12, Schedule B.5.4 as detailed in Table 6.

Table 6 Future Investment Mapping of Storm Restoration Projects

Projects Initiated in 2023	2023 Investment Exhibit A-12, Schedule B5.4 Location	Future Investment Exhibit A-12, Schedule B5.4 Location
EFC Communications	Line 40	Line 33
Pre-storm ADMS Enhancements	Line 40	Line 32
Post-Storm ADMS Enhancements	Line 40	Line 32

Q154. Are any of the Other Grid Modernization projects discussed in other company witness testimony?

A154. Yes, the Error Free Communication (EFC) project is an Other Grid Modernization project which is discussed in Part Six of Witness Hatsios' testimony. My testimony will describe Other Modernize Grid Management excluding EFC. The table below describes the breakout of Other Modernize Grid Management.

Table 7 Other Modernize Grid Management by Year ($000)

Project	2022	2023	2024	2025
Other Modernize Grid Management excluding EFC	3,660	24,430	2,200	2,500
EFC	4,140	1,970	0	0
Total	**7,800**	**26,400**	**2,200**	**2,500**

Q155. What is the OSI license investment?

A155. The OSI license investment refers to a financially prudent investment as part of Other Modernize Grid Management. Specifically, it entailed the acquisition of five year on-premise licenses for the Company's Outage Management System, which is mission-critical software.

Q156. What are the key drivers and benefits of the OSI license investment?

A156. This investment was an opportunity to purchase licenses on a 5-year term that would reduce the cost of these licenses by ~$1 million over that duration and shift the warranty period to cover that entire term. This change will allow the Company to save money and accurately project costs and ensure contractual service levels. The savings realized in this area will reduce the overall investment need. The enhanced warranty terms will benefit the Company's employees directly due to the increased support priority the agreement brings, and therefore support the Company's customers.

Q157. What factors drove the timing of the OSI license investment?

A157. This investment was undertaken now as the term of the current license and warranty period was due to lapse in the 2023 calendar year, allowing immediate savings to begin.

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Q158. What is the Qlik software license investment?

A158. The Qlik investment refers to a financially prudent investment as part of Other Grid Modernization. Specifically, it entailed the acquisition of a three-year license for the Qlik software, as the license was due to expire.

Q159. What are the key drivers of the Qlik license investment?

A159. The license, which was set to expire in September 2023, is crucial for the functionality of all applications utilizing OMS data through the enterprise data repository. Failure to renew this license would have resulted in our inability to use this important asset after September 2023. This would have directly impacted field efficiency, in the ability to receive updates from field resources (e.g., Outage Status Application) that is used to status work/crew assignments, add comments, upload pictures, update cause codes and estimated restoration times, etc.

Q160. What are the benefits of the Qlik license investment?

A160. This nearly instantaneous data source empowers applications and reports to aggregate and visualize OMS information. These reports and applications are used during outage restoration processes, analyzing hazard events, and proactively notifying field resources when critical events (large outages, hazards, etc.) occur on the system. This, in turn, enhances restoration processes and facilitates quicker outage restoration for customers.

Q161. What is the Current Transformer/Voltage Transformer (CT/VT) High Voltage Test Console project?

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A161. The Current and Voltage Transformer (CT/VT) Test Console is an end-of-life equipment replacement project. This system is used to perform accuracy & dielectric testing on medium voltage transformers.

Q162. What is the key driver of the CT/VT High Voltage Test Console project?

A162. The existing system is well beyond end-of-life rendering it virtually non-serviceable and unable to be restored in the event of a failure. This type of system is required to maintain the capability to calibrate and certify these transformers.

Q163. What are the benefits of the CT/VT High Voltage Test Console project?

A163. When implemented in 2024, this test system will provide capability to maintain billing accuracy compliance required by the MPSC. Furthermore, the system will enable testing of High Accuracy instrument transformers that the current system cannot support. High Accuracy transformers for metering applications have gained momentum as the manufacturing standard for revenue protection and regulatory compliance. This project removes the risk of losing the capability to perform a required function due to equipment failure.

Q164. Why is it important to undertake this project now?

A164. The existing system is not maintainable because many components and servicing options are no longer available.

Q165. What are the pre-storm season and post-storm season ADMS Enhancements?

A165. The pre-storm season and post-storm season ADMS enhancements are integral components of a broader ADMS enhancement plan that is discussed later in my

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testimony. They were strategically accelerated and scoped collectively, comprising a sequence of targeted upgrades and projects designed to enhance the Company's storm restoration response. These enhancements included direct upgrades to the ADMS applications, as well as upgrades targeting interfaces (e.g., AMI pre-processing), reporting applications (e.g., System Outage Screen), and more.

These enhancements align with the Company's commitment to storm preparedness and improving the response to severe weather events. The investments made before and after the 2023 storm season focused on improving response times, which includes quicker identification of outages (improvements to outage analysis, processing for momentary outages, event grouping, AMI/SCADA data processing) and faster outage restoration (bulk event updating, bulk crew assignment creation, reducing "okay on arrivals" to improve dispatching efficiency).

Q166. What is the key driver of these Pre-Storm and Post-Storm season ADMS Enhancements?

A166. The key driver of these ADMS enhancements was to further develop the storm response and communication capabilities of the current ADMS platform to meet changing needs and customer expectations. The series of severe weather events that occurred in parallel with the ADMS hypercare period highlighted that the Company needed to prioritize how outages were predicted, analyzed, and grouped for enhancement. The resulting changes better aligned the technology to show value and included considerable improvements as described later in my testimony.

Q167. What is the scope of work completed in 2023?

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A167. After go live in February 2023 and working with the new ADMS system through 2 storms, including the historic CAT storm, the Company identified program enhancements that would support even greater improvements in storm response. Throughout 2023 there were a series of targeted enhancements made to ADMS to drive improvements in safety, system reliability, usability, and restoration timing.

The scope of work completed is detailed below:

- Safety check feature – This enhancement mimics the safety check performed by a field crew before the crew closes an open switch between two circuits. Having this feature allows ADMS users (primarily system supervisors coordinating switching with field crews) to know if that safety check will pass or fail before putting a field crew in a position to have to perform that test.
- Enhanced outage prediction engine - This improvement to outage event/device prediction increased the prediction accuracy for larger, multi-circuit outages in the higher voltage network (stations, substations, subtransmission, etc.). This enhancement resulted in a reduced number of events that must be managed, and increased precision in communication.
- Outage analysis processing – These enhancements decreased the time it takes for AMI notifications and customer calls to be analyzed and associated to an event and device location, which reduces the time it takes to create a multiple customer outage event and dispatch a crew.
- Momentary outages detected by SCADA devices - This improvement in processing prevented sustained outage events from being created when customers have already been restored. This reduces crews from being

dispatched to outage events that are already restored and focuses their time on sites needing restoration.

- Event grouping - These enhancements reduce the time needed for dispatchers to analyze events before dispatching a crew, reducing overall restoration times.
- Wiredown grouping - This new functionality enables better insight into wiredown occurrences so that the right crews can be dispatched to the correct places for quicker restoration, thereby increasing public safety and reducing OK on Arrivals (crews sent to locations without active outages). For example, this feature enables dispatchers to group geographically located wiredowns to send the appropriate number of crews to restore an area rather than looking each wiredown as an isolated event.
- Outage analysis performance - These improvements directly impact how quickly customers are associated to an outage event and their capability to receive updates for their outages, as well as how quickly their outage can begin the restoration process.
- User interface improvements in new grid framework – These improvements allowed ADMS users to filter/group/sort events and crew assignments more efficiently. This reduces the time needed to analyze a large volume of events/crew assignments in the system and time needed to dispatch the required crews for an event.
- Switch Order Management (SOM) - With the completion of the transition period for the first phase of SOM on the ADMS platform, system operators within the Company's control room were able to begin using ADMS integrated with the work management system (Maximo). This enabled the creation,

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management, and completion of certain types of equipment shutdown coordination of the corresponding field work.

Q168. What are the benefits of Pre-Storm and Post-Storm ADMS Enhancements?

A168. These enhancements offer many benefits to the Company's customers, crews and overall operations, most notably in the areas of safety, system reliability, usability, and restoration. These enhancements have made the system more versatile and capable of meeting evolving customer needs and have streamlined processes and improved the overall efficiency of the system. By adding advanced features to existing capabilities, the Company has increased safety for customers and crews, built additional system reliability by removing risk for human error, and increased usability to move quicker to get crews dispatched timely and accurately which improves restoration timing while providing customers with more accurate restoration times.

ADMS Enhancement

Q169. What are ADMS Enhancements?

A169. As discussed in the ADMS section of my testimony, although all DMS applications were deployed in February 2023, the Company will continue to build upon this foundation by implementing additional modules and enhancements throughout 2023 and beyond. The investments in this category include operationalizing the additional modules of the ADMS to extract the full benefits of the ADMS. Additionally, as stated in the Other Grid Modernization section of testimony, the Company is leveraging the newly implemented ADMS systems breakthrough capabilities to improve storm restoration and customer communication. Initiated

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in 2023 after the catastrophic ice storm, these investments were expedited from the overarching ADMS enhancement plan to promptly deliver value to customers. The Company remains committed to sustaining and furthering these investments.

Q170. What are the key drivers of the ADMS Enhancements?

A170. The ADMS Enhancements are necessary to ensure that the Company operationalizes all the ADMS applications as planned to realize the full benefits of ADMS. Additionally, ADMS enhancements are necessary to keep up with the evolving needs and challenges of the modern electrical grid, as well as regulatory requirements and enhancements to strengthen cybersecurity measures to protect against potential vulnerabilities.

Q171. What is the scope of work planned for ADMS Enhancements in 2024 and 2025?

A171. The scope of work in 2024 and 2025 is focused on the eMap application, SOM phase 2, SOM phase 3, and added AMI functionality:

- eMap application
  - As the Company continues to operate and integrate this new technology, areas of opportunity to further enhance data and refine usage of this system are being exposed. These changes will allow the Company to quickly leverage the full capability of ADMS. The eMap is the intersection and operational interconnection of the as-operated state of the electric grid and advanced engineering data. This combination provides the Company the capability to enable novel applications, such as FLISR, which is an advanced application within DMS discussed later in my testimony.

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- Switch Order Management (SOM) phase 2
  - SOM phase 1 was implemented in 2023 SOM phase 2 includes enabling and activating switching and tagging, which directly relates to hazardous energy control and is one of the key Safety and effectiveness components of the ADMS vision. Phase 2 of the SOM implementation will permit DTEE ADMS users to create switching steps and execute orders related to those steps within the ADMS platform. Utilizing this capability in the tightly integrated ADMS platform means that users may be able to automatically model the state of the electric system on the ADMS eMap while performing work related to switching and tagging.
- SOM Phase 3
  - SOM phase 3 rounds out the utilization of the SOM application by focusing on the tagging aspect of switching and tagging. Fully integrating switching and tagging throughout DTE applications means that all switching and tagging must be electronic. SOM Phase 3 completes the transformation of switching and tagging into a fully electronic process by focusing on a digital version of red tag records. Red tag records are the way in which hazardous energy controls are documented. DTEE anticipates that this technology advancement will lead to additional business integrations and process improvements that will benefit the customer through an added layer of safety checks and efficiency-related opportunities.
- AMI Functionality
  - To further improve outage prediction and restoration additional AMI functionality will be incorporated with ADMS. This includes further integration of AMI voltage read data for energization/restoration

verification, visualization of voltage data, and aggregation/visibility on multiple customer outage events.

Q172. What are the benefits of the ADMS Enhancements?

A172. The eMap plays a crucial role in managing energy operations efficiently and ensuring reliability and stability of the power grid. Enhancements to the eMap are necessary and foundational to unlock advanced functionality in OMS, DMS, and SOM applications. For example, FLISR, an advanced application within DMS, is dependent on the eMap enhancement work in order to be enabled. This work benefits customers through improved restoration efforts.

<u>Operational Technology and Error Free Communication (EFC)</u>

Q173. What is the Operational Technology and EFC investment ?

A173. The Operational Technology (OT) and EFC investment is a collection of related investments that is sub-divided into two complimentary categories: OT investments and EFC investments. The OT investments support the operational activities required to ensure customer commitments, such as restoration times, are met. Whereas the EFC investments are focused on communicating with the customer on those operational efforts. These EFC investments are aimed at resolving communication challenges that lead to customer dissatisfaction.

The OT and EFC investments have resulted in, and continue to address, opportunities to accurately provide single estimates to customers and deliver effective communications to customers about the status of their restoration. The

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investments strategically align at various junctures ensuring a cohesive and fully coordinated set of effective communications for customers.

Q174. Is this project also discussed in another Company witness's testimony?

A174. Yes, the project has two separate but related parts. The EFC portion of this project is supported by Company Witness Hatsios. My testimony will describe the OT portion. Table 8 below describes the breakout between OT and EFC.

Table 8 OT and EFC Project/Projects by Year ($000)

Project	2022	2023	2024	2025
OT	1,254	84	2,400	800
EFC	4,242	52	3,200	600
Total	**5,496**	**136**	**5,600**	**1,400**

Q175. What work was completed in 2022 and 2023 for the OT investments?

A175. In 2022 and 2023 the OT investments were focused on the following projects: Type 2 Customer Communication & Processes; Outage Status App Updates and Security Upgrades; and the Pentos PPE Dashboard.

The Type 2 Customer Communication & Process project implemented three enhancements to improve the Type 2 damage claims process:

- Introduced new notifications to enhance communication regarding claim status.
- Implemented functionality to offer comprehensive status categories, involve key stakeholders, and transition Smartsheet functionality into SAP for improved user experience.

- Automated the Damage Claims Type 2 process for Electric and Gas customers from initiation to resolution. The primary goal is to minimize customer communication challenges related to their damage claims that often result in MPSC complaints, and to enhance communication and resolution timeliness for customers.

The Outage Status App Updates and Security Upgrades project developed a revised security framework for authorizing access to non-badged contractor crews through the Outage Status app. Prior to this project, contractor crews were required to be badged to have access to the Outage Status app, which is a tool utilized to perform their job duties. Being a badged contractor also allowed the contractor crews access to other Company information. The Company identified the need to restrict certain contract workers to updating the Outage Status app exclusively, therefore removing their access to other Company information. This required a new security configuration to allow non-badged contract crews access to the Outage Status app.

The Pentos PPE Dashboard project included the development of an employee tile in SAP to centralize and provide access to Personal Protective Equipment (PPE) information for Supply Chain, the Glove Lab, Supervision, and front-line employees. This dashboard was integrated into SAP Success Factors Tile for a unified platform managing all employees' equipment. Additionally, the project also included the implementation of self-service equipment ordering (e.g., PPE, rubber gloves, sleeves, calibration equipment) for both employees and admins.

These initiatives collectively contribute to enhancing operational efficiency, communication, and resource management within the OT space.

Q176. What is the scope of work in 2024 and 2025 for Operational Technology?

A176. In 2024 and 2025, specific investments are planned in the areas of Data Analytics and Data Engineering, Damage Assessment, DO RCO Enhancement GPS Productivity, and System Outage Screen (SOS) Hardening. As part of this work, investments in technology for Artificial Intelligence (AI) and Machine Learning (ML) will be included to enhance various aspects of operations. Specific examples include optimizing grid management, predictive maintenance, and improving overall system efficiency. These initiatives focus on bringing automation, data analytics, and intelligent decision-making into processes, contributing to increased reliability, cost-effectiveness, and sustainability.

Data Analytics and Data Engineering for Outage Restoration is a comprehensive initiative that leverages data science to improve the precision of outage restoration time estimates and enhance customer communications. This project involves substantial data engineering and data science efforts to ensure synchronization across various platforms, including outage management systems, AMI, customer services, and communications. The success of this project will be gauged by the accuracy percentage of the first-time estimate time of restoration (ETR) communicated to customers. Importantly, the metrics used to measure success will differentiate between storm and non-storm scenarios, providing a more nuanced understanding of our performance.

The Damage Assessment and Inspections Image Analytics project utilizes Artificial Intelligence (AI) and Machine Learning (ML) for image analytics to support the Damage Assessment process. This approach involves training models to identify equipment conditions and assess the extent of damage using images sourced from field personnel, damage assessors, or customers. This technology has the potential to be applied to day-to-day inspections, digitizing processes, and reducing manual work. By adopting image analytics, the utility aims to keep pace with peer utilities, while simultaneously enhancing reliability and improving the customer experience.

The DO RCO Enhancement GPS Productivity project is focused on upgrading the current GPS dashboard to address issues such as data errors, manual refreshing, and the need for real-time reporting. By leveraging modern technology and cloud-based platforms, the project aims to reduce manual tasks and provide same-day, real-time metrics. These metrics include vehicle time to leave, time to the first job, and time returned to the service center. The goal of the refreshed dashboard is to eliminate gaps in data, offering a comprehensive view of service center time metrics on the same day.

Within the OT investment is the SOS Hardening project. This project is focused on implementing enhancements to strengthen the resilience of the ADMS System Outage Screen (SOS) and its related capabilities, which includes the ongoing migration of crucial Azure infrastructure that supports SOS reporting and notifications within DTE's Azure environment. In addition, support is being provided for integrating the SOS application with the Outage Status Application (OSA) to enhance the client's Damage Assessment capabilities. The SOS

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application provides real-time visibility into customer outages, field crews, schematic diagrams, and other vital information necessary for effective outage management. The primary focus is on ensuring optimal performance, particularly under high-volume conditions during critical storm events. This is to ensure swift responses to customer outages before the upcoming summer storm season.

Customer Power Status Visibility Project (CPSV)

Q177. What is the Customer Power Status Visibility (CPSV) Project?

A177. CPSV represents the first in a series of planned projects whose objective is to begin the transformation of the Company's Advanced Metering Infrastructure (AMI) asset from a purely billing based design to a system capable of maintaining the billing excellence while adding in changes aimed at fully supporting the outage detection and response use case. This use case will materially improve the Company's capabilities related to energization status, outage detection, outage localization, outage response, customer communication and reduction of outage restoration duration.

Q178. What were the Key drivers for AMI when originally installed, and does that differ from CPSV?

A178. The Company embarked upon its AMI journey in 2009, installing a substantial, real-world pilot to demonstrate the ability to produce and deliver accurate customer bills based upon usage collected remotely, accurately, and efficiently. The AMI pilot and the resulting full-scale implementation of this technology, approved by the Commission in multiple subsequent rate orders between 2009 and 2019, resulted in the Company's ability to consistently gather usage data from ~2.3

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million residential electric meters and ~1.3 million residential gas meters. This eliminated the need to send meter readers out to collect that information which has alleviated personal safety concerns while reducing human error. While the Company intends to continue using this technology to maintain the same level of service for customers for this important set of billing benefits, this single primary use case for AMI meters is no longer sufficient to meet the needs of customers, communities, or the Company.

Q179. What are the key drivers of the CPSV project?

A179. The primary value driven objective of the Company's CPSV investments is to increase the volume of AMI outage and restoration messages received. The Company uses this information to provide communications to customers about outage occurrences, estimates of repair time, confirmation of outage status and in some cases the detection of nested outages. The Company will also be able to leverage the expanded set of AMI data to reduce cases of outage work remaining open that have been restored.

Storm events in 2023 highlighted a significant opportunity to improve the way the Company interacts with customers during these most impactful service interruptions. Customers expect that the Company knows before they do that their power has been interrupted, that the Company communicates with them appropriately, and that those communications are timely and accurate.

Since the February 2023 implementation of ADMS, the Company now possesses an OMS capable of leveraging information about a customer's power status,

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surpassing the capabilities of the previous systems. The collection and transportation of this data from the meter to the OMS requires a level of capability and capacity from the AMI system that was not part of the original design specification to which the system was constructed. With the OMS now in place, and having had multiple storm events in 2023 that provided data for analysis, the Company has closely examined the customer communication opportunities and determined an initial set of improvements that are the basis for this project.

Fundamentally, this project will enhance the existing AMI Network by identifying locations that lack the capacity to transport the volume of data needed from meters to the OMS system and adding additional network communication devices to those locations. These additions will be added in a structured manner based upon the number of customers served, reliability of the electric grid in that area, and reliability of AMI network in that area. Additional considerations, such as the communities served by that network segment, will be taken into account to ensure the Company effectively supports its most vulnerable customers.

This project will focus on maximizing the:

- Number of customers that are included in outage communications
- Accuracy of the first and subsequent estimate provided to customers
- Timeliness of delivering first estimates to customers
- Ability to predict customer outages where no direct information is available
- Reduction of OK on arrivals

Q180. What is the scope of work planned for 2024 and 2025?

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A180. The CPSV Project will achieve its objectives through a combination of the following scope items:

- Replacement of 3000 end-of-life Field Area Routers (FAR) that are no longer performing their intended function in all weather conditions, with up to date and fully functional devices. This replacement will result in more meter alarms and voltage information reaching the AMI system for use by the Outage Management System, Customer system, digital channels, and error free communications infrastructure. These FARs will now have a direct connection to the AMI system reducing the number of communications hops currently in the system to zero.
- Installation of 500 additional FAR's to be placed in densely populated areas reducing the number of meters each FAR manages to minimize data loss from oversaturation.
- Installation of 22,000 cellular meters placed strategically at premises adjacent to automatically resetting distribution circuit breakers (known as Reclosers) to understand the energization status of that circuit segment without having a SCADA device installed at that location. This will allow system operations to more accurately model and isolate outages.
- Deployment of in premise or on meter communications devices in areas where mesh design or other factors make meter communications intermittent as a secondary way of understanding the power status at select premises (prioritization to schools and our most vulnerable customers).
- Deploy a suite of monitoring and visualization tools for real time information on all components of the AMI network for operational response.

- Design, staff, and deploy a permanent AMI Network Operations Center to monitor the AMI communications network with rigor and operational awareness at the same level the electric grid that it serves is monitored. This staff will include dedicated headcount to perform this monitoring, dispatching crews and the field crews themselves, all tasked to keep the AMI network operational during all weather conditions.

Q181. What are the benefits of the CPSV project?

A181. The CPSV Project will provide the following benefits by the end of the Phase 1 period ending in December 2024:

- Maximize the Number of Customers that are included in outage communications. In 2023 the Company included ~60% of customers in proactive customer communications. This is driven by the commitment to only communicate with customers when there is certainty of up to date and accurate information. If that information is uncertain then proactive communications are not undertaken. When this project completes its Phase 1 objectives this percentage will bring the overall percentage to ~72%, thus adding more than 250,000 customers that will now have the ability to receive proactive and accurate communications from the Company.
- Maximize the accuracy of the first and all subsequent estimates provided to customers. DTEE measures estimate accuracy for all customers that have meters that successfully provided a Power Out Notification to the AMI system. With the planned network improvements that population will be increased by 10-15%.

- Maximize the timeliness of delivering a first estimate to the customer. With more alarms and voltage information making it to the AMI system the Company will be able to more quickly isolate and assess damage locations and severity improving time to deliver the first estimate by 10% by the end of Phase 1 which will improve on our existing first estimate delivery commitment by between 30 and 45 minutes during major storm events.
- Maximize the ability to predict customer outages where no direct information is available. There are some number of customers that experience an outage and neither the AMI information nor a customer call is available. These customers are identified by predicting their status based on information derived from information from their area and other confirmed outages. More available information reduces the number of outages that must be predicted and increases the accuracy of the OMS outage prediction engine. By the end of 2024, this project will increase the accuracy of these predictions by 10 – 15%.
- Minimize the number of OK on Arrivals. Due to the nature of a large-scale event like a storm there are restoration jobs where a customers' power is restored and the OMS still has an active job or jobs associated with this customer. Sending a crew to a job that is already restored wastes valuable restoration capacity and prolongs the restoration of real ongoing work efforts as crews report to already resolved outage situations. The Company can locate instances of this condition if it can reliably get the meter status at these locations and use that information to determine if a crew is really needed. At the end of 2023, the OK on Arrival percentage for outage jobs during storms was 26%. This project will reduce that percentage by ~25%, bringing the overall rate for OK on Arrivals during storms to ~19% before other additional improvements

to processes are factored in. Using our most recent storm event in 2024 this improvement, had it been executed prior to that event, would have prevented ~250 number of truck rolls saving ~$250,000 (250 x 1000 calculated cost per crew per assignment) and shortened the overall restoration effort by 4-6 hours to closure.

Advanced Metering Infrastructure (AMI) Meter Communications Upgrade

Q182. What is the AMI Meter Communications Upgrade?

A182. While the CPSV Project represents adding additional capability to the AMI network through redesign and the additional capacity/capability that a denser network device deployment will enable, the AMI Meter Communications Upgrade project represents the capital hardware investment needed yearly to replace end of life devices or those destroyed in the field due to weather events or other incidental damage. There is an ongoing need to procure and install a portion of the fleet of devices each year as part of ongoing pacing of replacement. While included as part of DTEE's strategic projects in the current case, this investment will be covered as routine replacement capital in future rate cases.

Q183. What are the key drivers of this program?

A183. Every year there is a portion of the network devices, primarily field area routers, that reach the end of their useful deployed lifecycle or are damaged in place because of weather events or other operational events like third party damage and the build out of new attachments. These devices must be installed and placed into service to ensure that the communications network retains the ability to reliably cover the

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service territory. This investment is key to continuing to deliver the value already being derived from the AMI system.

Q184. What are the benefits of this program?

A184. This investment allows the Company to continue to deliver accurate billing, offer and manage new rate structures including the Time-of-Day rates, and contributes to the timeliness of outage restoration. Much like other ongoing capital investments in the health of the grid this investment protects performance of these assets throughout the system's deployed lifespan.

Q185. What is driving the timing of this investment?

A185. Like any project or program of this type, this spend represents the planned and timely replacement of these devices within this period. That means that there needs to be a yearly investment in these asset replacements. Failure to make this investment will result in an increased likelihood of estimated bills for customers in areas where this equipment fails to operate as expected, potentially extending restoration times during outage events due to less certainty of energization state, and leading to fewer, less accurate communications to customers.

Microwave End of Life

Q186. What is the Microwave End of Life Project?

A186. The Company owns and operates its own set of microwave communications installations. As the network grows, DTEE must replace aging assets as well as add components to strengthen, tune, and optimize the system. This investment includes replacement of microwave paths, enhancements to stabilize the microwave ring, and support changes mandated by the FCC in deregulation of the 6 gigahertz (Ghz) frequency.

Q187. What are the key drivers of the Microwave End of Life Project?

A187. Due to FCC deregulation of privately owned frequencies, DTEE must replace several microwave systems to maintain a reliable network and avoid collisions with other entities using the same frequency.

Q188. What are the benefits for the Microwave End of Life Project?

A188. These efforts provide overall improvements to infrastructure redundancy, availability, capability, and security and are being coordinated with the Grid telecommunications program fiber installations to increase resiliency and provide additional network capacity. Upgrading the microwave transport systems serves SCADA reliability, AMI, and provides business intelligence around storm related damages.

Q189. What has been accomplished in 2022 and 2023 and what are the scheduled plans for 2024 and 2025?

A189. In 2022 and 2023 the Company put into service several new communication support assets targeted at both enhancing existing microwave communication capabilities and securing communications capabilities for the future.

In support of this in 2022, the Company erected a new tower in Marysville to house new 11Ghz microwave equipment that provides communication between Belle River and Marysville because the existing tower no longer met updated safety

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regulations and the new tower supported the installation of a larger number of modern microwave receivers and transmitters. As a result, the Company replaced a leased service link by installing a new microwave path between Hancock substation and the Wixom Pole Yard, reducing overall operational costs.

In 2023, the Company put into service a Frequency Assurance System that allows management of interference on existing microwaves still in use. The Company is on target to complete 3 more updates to 6Ghz equipment by the end of 2024.

In 2024 and 2025, the Company will continue to replace both licensed critical paths and unlicensed paths. The implementation of path replacement will improve quality of service, reliability, and allow the Company to release leased telecom services, having replaced them with privately-owned communications, which will reduce operational costs.

<u>FLISR Implementation</u>

Q190. What is Fault Location, Isolation, and Service Restoration (FLISR)?

A190. FLISR is a sophisticated software application that integrates with the other ADMS platform applications, such as Distribution Power Flow (DPF), to enable efficient fault response and power restoration. FLISR combines advanced automation, real-time data analysis, and decision support tools to quickly detect, locate, and isolate faults before restoring power in the event of faults or outages. FLISR is able to function by utilizing information from various sensors, devices, and communications networks. In detail, the components that enable the full functionality of FLISR are as follows:

- Distribution Power Flow (DPF): This component is the foundational/prerequisite application that calculates the power flows and voltages through the eMap network model. This application is required for the sequentially-occurring components of FLISR to run. FLISR uses the output of DPF to estimate how much fault current would be created if a fault were to occur at any point on the eMap. When a fault occurs on the Company's electric system, FLISR can combine status indications and analog fault currents to estimate where that fault occurred.
- Fault Location ("FL" in FLISR): Fault locating estimates the location of a fault after it occurs on the electric system using fault indicators and fault current measurements.
- Isolation ("I" is FLISR): Isolation is the process in which the fault is separated/isolated from the rest of the electric system by using available switching devices to create an isolation zone.
- Service Restoration ("SR" in FLISR): Service restoration is the process in which electric service is restored to customers outside of the isolation zone without creating loading/voltage violations.

Q191. What are the key drivers of FLISR?

A191. This investment provides fundamental support to DTEE's initiative to improve overall outage restoration and storm restoration commitments, and the Company agrees with the Commission's statement in Case No. U-21297 that, "outage restoration is a critical area" (U-21297, pg. 114). The continued investment in FLISR will help the Company improve storm restoration via reduced outage duration, as well as enable the Company to continue realizing the full benefits of

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ADMS and automation. Achieving a fully functioning FLISR that operates automatically and safely unlocks an incremental benefit in automating the "isolation" and "service restoration" portion of FLISR.

The ability to isolate and restore in near real-time is dependent on both FLISR and field equipment that is described in the Distribution Automation section of my testimony. As DTEE system capacity increases and as there is an increase of SCADA penetration, the Company will be able to use FLISR to aid in reconfiguring the electrical system when a fault occurs and reduce outage size and outage duration for customers overall.

Additionally, the components of FLISR allow the Company to respond to undesirable situations on the electric system in a fundamentally different way. The isolation/service restoration functionality will now allow for the near-real-time use of non-protective devices to isolate faults by creating an isolation zone and restore service to remaining customers by transferring them to adjacent circuits. This is different from how the current system is set up to operate near-real-time and creates more opportunities to impact customer outage size/duration than available currently or that has been historically.

Q192. What are the benefits of FLISR?

A192. FLISR offers an array of benefits to DTEE and its customers. Improved fault locating logic will reduce outage duration and decrease strain on devices involved in local logic fault hunting schemes. On-demand isolation and service restoration plans will provide quick and precise ways to reduce the size of outage events in periods of low and high loading. These beneficial advancements align with other DTEE initiatives to increase SCADA penetration and grid capacity.

Improved fault locating logic benefits customers experiencing a sustained outage by allowing DTEE to send crews to an estimated fault location instead of needing to perform longer patrols. This becomes especially important in certain areas within the electric system, such as the subtransmission network where crew patrols may take longer due to long distances/overhead line miles that need to be patrolled. This directly impacts the overall customer outage duration by reducing a key part of the restoration timeline (crews patrolling for exact location of damage before repairs can be made and customer's power restored). Getting to the location quicker where repairs need to be made reduces the overall duration of the power outage, directly impacting DTEE's SAIDI.

On demand isolation and service restoration reduces the size of sustained outages by quickly restoring some of the customers in the initial outage area. The total number of customers interrupted with a sustained outage is reduced when isolation and service restoration occur. Within a short period of time after isolation/service restoration occurs, the customers that are outside of the isolation zone are not impacted with a sustained outage and reduces the overall number of customers affected for the sustained outage event, directly impacting DTEE's SAIFI.

These combined benefits result in all-weather SAIDI improvements for DTEE's system. The two main benefit drivers are fault location identification and restoration switching analysis. Fault location identification was estimated to have

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5-10 minutes of all-weather SAIDI benefit and restoration switching analysis is estimated to have 4-14 minutes of all-weather SAIDI benefit.

Q193. Are other benefits expected to be realized?

A193. Using the centralized logic FLISR provides instead of current local fault hunting logic will reduce the stress incurred by devices on the subtransmission system and loop schemes. This can prolong the usable life of such equipment.

DTEE's loop schemes also face challenges on many circuits caused by limited capacity. There are some situations where the loop scheme is unidirectional. This means that one circuit can host load from an adjacent circuit, but the adjacent circuit cannot host load from the first circuit. There are other situations where a loop scheme is disabled outright during periods of high loading because the loop scheme operation may result in system violations. The centralized logic of FLISR does not require one-way configurations or preemptive disabling. Rather, it uses the real-time state of the electric system as modeled in the eMap, SCADA indications, and forecasted loading to make decisions in the moment of whether service restoration is permissible. The dynamic decision-making process can result in successful service restorations in situations where the local logic may have been defeated.

Additionally, FLISR can be enabled one feeder/source at a time, as outlined in the implementation plan further down in testimony. DTEE and customers start gaining the benefits for feeders where FLISR is enabled incrementally as it is being implemented over time, and do not have to wait for the full FLISR implementation across the entire system to start gaining benefits from it.

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Q194. What is the implementation plan for FLISR?

A194. The implementation plan for FLISR is a step by step, incremental capability implementation. With this plan, the DTEE grid will see incremental benefits every year, as opposed to an investment where all benefits happen after completion at the end of the project. The initial part of the plan will start with the fault locating functionality within FLISR, then continue to implement isolation/service restoration. As DPF is converging and FLISR turned on for fault locating there is incremental gain. As more devices are added it will incrementally gain some more. FLISR is aligned to a 5-year plan to coincide with the installation of the SCADA enabled field devices that the series of ADMS applications (including FLISR) will automatically control. In the first year of the project, the Company will focus on enabling fault locating where possible in conjunction with developing an implementation schedule that will move each source/circuit from initial fault locating capabilities to the automatic processing for full fault locating/isolation/service restoration via switching to restore customers. This final step will achieve the full benefits of FLISR.

To achieve the desired outcome for complete FLISR automation, there are three key areas that will be supported to get there.

- System integration – Integrating FLISR within established infrastructure. The process for managing field devices (both currently installed and future devices) and incorporating them into the system. This includes smart fault indicators, power quality monitoring devices, low-cost monitoring devices, form 6 reclosers, distribution PTDs, micro-processor relays, Viper reclosers, etc.

- Grid model tuning with FLISR – Assessing the network model in ADMS to identify the regions for tuning, creating the plan for engineers to conduct grid model tuning, and reporting to document the process/outcomes, and monitor functionality, performance, and any issues/challenge encountered during the process.
- Distribution Power Flow (DPF) convergence support – Iterative testing and tuning/configuration to ensure convergence and high-quality results (e.g., precision of topology and power flow results)

Distributed Energy Resources Management System (DERMS)

Q195. What is the DERMS?

A195. The electric grid in the future will need to incorporate new technologies, including Distributed Energy Resources (DER) such as solar and battery storage. To enable and support the grid benefits of these resources as well as manage the complexities of intermittent and two-way power flow, utilities must plan for DER integration. DERMS is a control system specifically designed to handle DERs at the residential, commercial, and industrial, and distribution grid levels. A DERMS acts as a switchboard for DER-related protocols and information to simplify the management of these disparate systems and feed information into other utility backend systems for planning, operations, and customer engagement. In addition to solar and storage, these DERs can include demand response, electric vehicles, or other distributed technologies.

Q196. What functionality is present in a DERMS?

A196. A Utility DERMS is composed of multiple key functionalities:

- Track the location, status, configuration, and capabilities of all DER on the electrical system.
- Track the energy management and economic program assignments, criteria and constraints for each DER and identify and prevent conflicts.
- Provide interfaces to all of the DER related protocols, controls, both utility controlled, and vendor controlled, and interfaces to utility information systems such as Customer Relationship Management (CRM), Billing, Market Systems and the ADMS.
- Provide the capability to capture data, availability, and performance from the DER, either directly or from third parties and to send dispatch commands to those devices.
- Forecast the real time and short-term availability, energy balances, and capabilities of registered DER, this includes Demand Management and Response which coordinates solar, storage and flexible loads to regulate peak demand, execute energy efficiency, and align with utility and market programs.
- Optimize those dispatch commands both for energy savings and economics, all while maintaining and respecting program constraints, customer decisions and grid constraints and maintaining the operability of the electrical system.
- Management functions of the DERMS are to aggregate DERs into groups that can be more easily coordinated, controlled, and dispatched, and automate the dispatch and optimization functions with algorithms to support Transmission and Distribution System coordination while balancing Market and real time operational constraints.

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Because of this broad scope, a DERMS system must have interfaces to nearly all utility systems, most importantly the ADMS, market and the customer information systems.

Q197. What is the benefit of a DERMS?

A197. The DERMS provides a central location to consolidate interfaces to different DER types and vendor systems and present it consistently to the ADMS. Without this consolidation each different type of DER or vendor system would need a custom integration to the ADMS and changes to vendor interfaces would impact ADMS operations, making each integration more costly and time consuming. The DERMS also provides optimization of dispatch of DER, allowing the system operator, or market signal, to set a dispatch goal in the ADMS for a specific area of the system. The DERMS evaluates the available and registered resources to accomplish the goal, balancing DER constraints and customer impacts with the timing and duration of the dispatch.

Q198. What is the optimal timing to begin DERMs implementation?

A198. DTE will begin investment in DERMs in 2025. This will allow a clear evaluation of MISO FERC 2222 requirements that will be available by Q3 2024. Electrification and DER adoption will only increase over time, and more complex DER hardware is being made available to customers available to customers continuously. To meet customer needs and provide necessary operational coordination it is imperative to have a working system in place to support these capabilities. The complex implementation of a DERMS must begin now to allow adequate time for the number of interface and system changes required, and to

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procure the necessary functions for compliance. In addition to preparation for future needs, immediate benefit from a DERMS can be realized through integration of many existing programs, producing streamlined coordination with the control room, and generating benefit from initial investments including demand response and load control programs.

Q199. What is DTE's strategy for deploying a DERMS cost effectively?

A199. The Company's strategy is to focus on the areas where DERMS is needed for compliance and areas where it can increase the efficiency of existing processes and systems and build interfaces or consolidate systems that currently do not work together. This approach is a System of Systems, where components are implemented as they are needed and at the scale that they are needed. Some of the first components that are needed are consolidation of management systems that coordinate DER and DR data and program participation and interfaces to the ADMS. This will allow current DR and DER programs to be tracked more efficiently, benefitting customers that are currently in DR, load management and DER programs and enabling the dispatch of larger existing SCADA controlled assets in coordination with the ADMS and Market Systems to support currently implemented programs such as FERC841. Future phases will focus on the forecasting and optimization as well as automation of constraint management and Distribution System Operator (DSO)/ Transmission System Operator (TSO) coordination.

Q200. What is the scope of the investment in DERMS in 2025?

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A200. The initial investment will be in the program and configuration database to centralize program management, program constraints and the tools to assign DER to system model nodes. This will be done in parallel with ADMS enhancements to be able to control dispatch of identified resources and enforce constraints at circuit level granularity. These first interfaces will utilize existing programs including Commercial Interruptible customers, Demand Response, Interruptible heating and air conditioning and Load Management System functionalities and other DER programs. DTEE has identified a key list of requirements for framework, functionality, demand response, and integration into utility systems and is currently evaluating vendors to identify the partner best able to satisfy all needs.

Q201. Will this approach be able to scale to support the state's clean energy transformation?

A201. Yes, this approach allows for capacity to expand while adoption rates of DER are growing. Approaching the complicated problem of a DERMS by addressing fundamental systems and data and investing in and implementing components as they are needed and at the scale they are needed, the DERMS implementation will be able to benefit existing customers participating in DR and DER programs today and expand as FERC 2222 and other future programs are brought online. As DER integration grows, the speed of adoption is still uncertain, and it is not practical or cost effective to implement a system that can initially provide the capability to support millions of customer DER that may not materialize. However not having a system to manage DER in a comprehensive way would lead to potential non-compliance, inefficiencies, and degraded customer experience.

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Substation Cybersecurity Program

Q202. What is the Substation Cybersecurity Program?

A202. As technology and automation investment grows, the number of devices deployed on the grid will also grow, driving a need for increased cybersecurity to protect the devices and grid controls. The Substation Cybersecurity program will develop and deploy cybersecurity tools supporting the increasing use of distribution automation devices across DTEE substations and circuits. This program aligns with the NIST Cybersecurity Framework (National Institute of Standards and Technology), Cybersecurity program management and architecture requires situational awareness, threat and vulnerability management, asset and configuration management, and incident response among other activities.

Q203. What is the scope and benefits of the Cybersecurity Tools program?

A203. This project made improvements to the physical security at Stone Pool substation in 2023 as well as procurement and testing of software for situational awareness, threat and vulnerability management inside the substation, and asset and configuration management. In 2024, penetration testing, and further integration of physical and cyber alerts will be completed to close out the Stone Pool Substation portion of the project. This work will ensure robust protection at Stone Pool as well as inform standards, policies and procedures to ensure cybersecurity at future substations and inform optimal mitigations at other existing substation in the future. Work in 2024 and 2025 also includes the procurement of distribution device compatible cyber security hardware that can be used to secure devices that are deployed on distribution circuits and the collection of industry data and best practices for cybersecurity for circuit level distribution assets including an independent threat and vulnerability assessment of these approaches. This work will inform future process and program developments to ensure increased monitoring and control of the distribution system is paired with the necessary increases in cybersecurity.

<u>Automation Configuration Database</u>

Q204. What is the Automation Configuration Database Project?

A204. The Automation and Configuration Database is an investment in tools for improved tracking of intelligent electronic devices, specifically distribution relay and network communications equipment. As distribution automation equipment becomes ever more sophisticated it is important to ensure more detailed information about devices is retained and leveraged. Traditional relay database may only capture items like device type and settings, as devices become more sophisticated it becomes important to track additional information such as device configurations, software version, and firmware status. It is also important that this data be stored in a readily accessible way to allow for connection with other data systems, effective patch management, and cybersecurity monitoring. This project will replace the existing in house database with an industry standard tool, improving data accessibility and ability to coordinate asset, work management, and protection data between databases increasing work efficiency and supporting increases in automation resulting in faster design of projects for customers, reductions in commissioning and maintenance duration where equipment is out of service and minimize the chance of devices being misconfigured or having out of date settings that could adversely impact customer reliability.

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Q205. What is the scope of work on the Automation and Configuration database for 2024 and 2025?

A205. The 2024 scope will include the software evaluation and selection as well as verification of compatibility of relay test equipment with software selection. 2025 scope will include data cleansing and implementation of the database as well as establishment of connection between relay test equipment and automation and test record database.

H. Distribution Planning

Q206. What is the Distribution Planning investment category?

A206. The dynamic nature of the grid requires that engineers regularly analyze grid capabilities including capacity, reliability, and adequate voltage support, to support integration of new load and other new customer needs such as DER. Distribution Planning is a category of investments in the tools, processes, software applications and data models supporting the near and long term planning of the distribution system. It includes the applications to correlate and consolidate changes to the electrical system model so that the different planning tools and the ADMS can utilize the same data set to perform the necessary analysis for power flow, power quality, contingency analysis and project scenarios. These tools assess the impact of bulk power system modifications, customer requested interconnection and loading changes, and utility initiated upgrades to the electrical system. This category also includes the tools to assess the civil, mechanical and structural aspects of project engineering and design. In concert, these tools and systems allow the Company to optimize projects and consider alternatives in a quantitative and physics-based manner.

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Q207. Where are the capital investment details of the projects and programs in this category?

A207. Capital investment details of these projects and programs in this category are included in:

- Exhibit A-12, Schedule B5.4, page 17-18
- Exhibit A-23, Schedule M7

Table 9 Distribution Planning Investments Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
ADMS: Network Management System	p. 18, line 41	pp. 12-16	pp. 150-155
Load Forecasting & Analytics	p. 18, line 42	pp. 92-95	pp. 150-155, 244
Interconnection Process Enablement	p. 17, line 29	pp. 87-91	pp. 150-155, 246-249
Hosting Capacity Enablement	p. 18, line 43	pp. 83-86	pp. 150-155, 250-251
Power Quality Analysis Program	p. 18, line 44	pp. 169-172	pp. 150-155, 251-252
Substation Design Tool Upgrade	p. 18, line 45	pp. 197-202	pp. 150-155, 252
Distribution Planning	p. 18, line 46	pp. 50-53	pp. 150-155
SCADA Remote Access and Configuration Platform	p. 17, line 19	pp. 177-180	pp. 150-155, 243

Q208. Why is investing in technology for Distribution Planning essential for DTEE and customers?

A208. These investments incorporate enhancements to existing tools, new tools, and interfaces to allow more frequent and accurate modeling of the distribution system and analysis of planned changes. A number of different tools are used by engineering and design during the development of a project and during annual system studies. The investments in these different tools keep them up to date, add enhancements and capabilities and improve the efficiency of the design process. Distribution planning encompasses tools needed for distribution planning, design, specification, modeling, forecasting and the analytics of associated data. This area accounts for systems and engineering tools needed to perform modelling functions accurately and effectively for all distribution planning activities and investments. These individual tools are also used by planning engineers in modeling grid impacts and the calculations needed to implement projects to design standards. These investments support streamlining the customer interconnections process and include investments in hosting capacity mapping.

Network Management System (NMS)

Q209. What is Network Management System (NMS)?

A209. As part of the ADMS project, the Company implemented a Network Management System (NMS) in 2020. NMS incorporates network data from the Geographic Information System (GIS) and combines the network data with other systems to directly serve the new ADMS functionality. NMS consolidated multiple network models to one common network model, resulting in a consistent view of the electrical system in real time to be used by all functions of the ADMS. Moving from multiple networks models into one had many advantages, it promotes data consistency, simplifies maintenance, improves integration capabilities, and leads to operational efficiency. This data model is also used by the distribution planning tools to provide the base model information for all planning studies.

Q210. How was the NMS program structured and implemented?

A210. The NMS program was broken up into multiple phases to align with the short-term and long-term data requirements for ADMS and other projects. The initial phase of NMS included implementing operational dashboards for monitoring data quality, employing machine learning models to correct data issues, and consolidating multiple sources into a single location (GIS) for use in external systems. In 2020, following the successful completion of the initial phase and setting the foundation for maintaining high-quality systems for data, the Company adhered to its plan by advancing the NMS investment. Additional initiatives were implemented to improve and add more information into our network model, enabling future technology investments and existing technology enhancements to maintain a high level of accuracy.

The NMS investments, which are described in detail later in my testimony, are targeted to four areas of focus:

1. Common Platform: Moving to a shared technology foundation that facilitates seamless interaction and collaboration between different systems, applications, and devices. This allows for data to be extracted from the source and eliminates potential for human error. For example, distribution circuit operating maps will be directly generated from the GIS, ensuring more accurate data for field and system operations. This avoids the work delays that field workers currently encounter when manually reconciling map differences, allowing restoration work to happen faster.

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2. Network Model Enhancements: Involves improving and expanding the representation within the network model. It includes adding new data fields, refining existing ones, and incorporating more accurate and detailed information to capture the characteristics of the network. The goal is to enhance the model's accuracy, completeness, and usability for applications that use the data.

3. Grid Model Analytics: Centers on using analytics to gain insight into behavior, performance, and characteristics of the grid. The objective is to improve reliability, efficiency, and overall functionality of the electrical grid by leveraging data-driven insights derived from the grid model.

4. Asset Data Integration: Consolidates data from different databases, sensors, and sources to create a unified and comprehensive view of the assets. The goal is to enhance data accuracy, accessibility, and usability, enabling better decision-making and management in a coordinated manner.

Q211. Has the MPSC supported past investments in NMS?

A211. Yes. On Page 116 of the December 1, 2023 Order in Case No. U-21297 the MPSC stated that "The Commission agrees with DTE Electric that "[g]rid needs are dynamic, and the tools to support reliability and grid modernization also need to adapt and develop to support these emerging grid needs." 5 Tr 2945." and the amount requested by the Company was approved.

Q212. Will continued investment be needed for NMS?

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A212. Yes. As the electric grid continues to change, the systems that support the management of the electric grid will also need to be updated and change. Sustained investment provides critical source data for operational systems (e.g., ADMS – DMS network model application), and is the basis for an accurate interpretation of the current status of the electrical system. This is essential for the safe and effective monitoring and operation of the electrical grid. Specifically, these initiatives will improve the Company's capability to analyze electrical load distribution, identify overloaded areas in the network, and plan upgrades more effectively. This approach enables the Company to accurately model and analyze growing electrical demand and improve service quality and reliability for customers.

Q213. Since the initial NMS Implementation, what has been accomplished to date?

A213. To date, there have been prudent investments made in the four areas of focus:

- **Common Platform:** 328 operational maps have been converted.
- **Network Model Enhancements:** 30 new data fields have been added to the network model.
- **Grid Model Analytics:** Data quality for dynamic protective devices and capacitors improved by 18% in 2022, and data quality for switches, fuses, and regulators has improved by 30% in 2023.
- **Asset Data Integration:** 8 asset types were synchronized between GIS and Maximo and new data governance was established with clear data ownership accountabilities and support processes. In 2023, the AC network meter connectivity pilot was brought to completion and the NMS started supporting Distribution Power Flow (DPF) application in enhancing the network data models.

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Q214. What are the plans for NMS in 2024 and beyond?

A214. The focus for 2024 is on supporting and strengthening DPF and FLISR applications by developing new network models and augmenting existing network models with the addition of 10 new data fields . The objective for grid model analytics is to improve the data quality for primary and sub-transmission OH and UG lines by 10%. In addition, the Company will invest in AC network connectivity and asset data integrations by synchronizing 4 asset types between GIS and Maximo. Future plans are to continue to support DPF and FLISR applications and continue implementation of AC network connectivity. For network model enhancements, the goal is to add 5 new data fields to the network model and improve and develop new algorithms to enhance phasing and meter to transformer connectivity. In grid model analytics, the target is the improvement of data quality for smart fault indicators and DERs by 10%. These continued investments contribute to the Company's capability to identify areas with high demand or vulnerabilities in the grid. Using this data to improve our planning processes results in higher quality customer service improvements.

Q215. What are the benefits of the investments in the Network Model for the Company's customers?

A215. High-quality data is the backbone of the ADMS system, and ADMS is central to day-to-day and storm grid management. Investing in data quality improvements is foundational to enabling all the potential value in the remaining ADMS components.

As an alternative to NMS enhancements, manually performing the functionality provided by network model investments would require an estimated 20 additional

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Full Time Employees (FTEs) to manually maintain data between systems (for example, synchronizing the location of the assets, operating voltage ratings, etc., across the systems). Highlighted in Case No. U-21297 by Witness Reterstorf (5T 2911-2912), the Company referenced an avoidance of 20 O&M personnel due to continued investments in NMS (at the time of filing U-21297, the cost of adding 7 of these 20 personnel was avoided). At the time of filing, DTEE estimates that the cost of adding 14 of these 20 O&M personnel has been avoided as a result of these Network Model investments. DTEE is on track to achieve the 20-FTE target by the end of 2024.

Q216. Can you describe the realized and projected operational benefits of the additional investment in the four focus areas of NMS?

A216. Investments to date have improved the Company's operational ability to generate maps from GIS, improved load analysis ability, and enabled more accurate preventative maintenance planning. Combined with the remaining work in 2023, this investment will continue to improve the data quality as outlined below.

1. Common Platform: The transition to a single platform will provide more accurate Network Model data for field operations by directly generating operating maps from the GIS and eliminating the CAD tool.

2. Network Model Enhancements: These enhancements will improve downstream processes—including distribution planning, grid operations, and customer interconnections—resulting in more accurate data models. The new data fields added to the model each year across the system to further understand and quantify the effects of these types to the network model.

3. Grid Model Analytics: These machine learning models will be run periodically to identify and correct data within the base Network Model. Improvements in data accuracy and availability address attributes such as KVA, operating voltage, and phasing.

4. Asset Data Integrations: Synchronizing the data in the GIS platform with the data in the work management platform (Maximo) will provide accurate asset data to improve preventative maintenance schedules, ultimately improving system reliability.

Load Forecasting & Analytics

Q217. What is Load Forecasting and Analytics?

A217. Load Forecasting and Analytics is a program that represents investments in planning tool capabilities that are focused on the essential industry standard distribution planning tool CYME that models distribution circuits and calculates load flow, and the load analysis tool Power Runner which combines SCADA, AMI and forecasted load data to generate load allocation scenarios to CYME. This category of investments include required software licensing, associated server hardware, interfaces, and functionality enhancements for this software and supporting planning tools.

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Q218. Did the commission order in Case No. U-21297 express any concerns about these investments?

A218. Yes, the order indicated that additional evidence to support the investment was needed, and also raised a question about accounting related to the amount of labor when compared to materials. The following testimony details the program and investments to provide additional evidence.

Q219. What investments were made in 2022 and 2023 and what are the benefits to customers?

A219. Investments in 2022 and 2023 included the upgrade of the CYME distribution planning tools and required licensing and server hardware to the latest supported version which will enable improved modeling for hosting capacity and non-wire alternatives and allow for new modules that will be implemented in 2024 and beyond. Investments also included the initial deployment of Power Runner licensing, servers and software that combines SCADA, AMI and forecasted load data from every meter on the system, to produce hourly load allocation curves. For subtransmission tools, TSAT software and required license was purchased as it is now a requirement for MISO Dynamic model studies.

Q220. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A220. 2024 investments include enhancing CYME to load data from Power Runner to allow for multi time period scenario analysis and the implementation of CYME Advanced Project Manager which allows sequencing of system model changes to project plans and linkage to Maximo workorders. Enhancements will also be made

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to allow for substation models to be loaded into CYME to improve the analysis of circuit load transfers, conversion, and consolidation. The combination of Dynamic Data Pull (DDP) module for load allocation and Advanced Project Manager (APM) module allows projects to be studied in multiple phases and validate that schedule changes to project do not violate constraints. This will also improve interconnection studies as the in-service date of projects can now be considered for coincident projects to determine interactions. 2025 enhancements to CYME will begin the implementation of the Advanced Distribution Planning System which is a collection of CYME enhancements that are being implemented at other utilities that address DER and NWA scenario planning and automate many common tasks and reports that are run by engineers. Power Runner will be enhanced to provide more validation of load profiles and be integrated with as-operated status of the system to better model load transfers and switching. Power Runner will also incorporate the sub transmission model hierarchy to allow for preparation of sub transmission loading data sets into tools like PSSE. PSSE enhancements will be made in 2024 to comply with MISO MOD32 data modelling requirements and to perform new gross load calculations at model nodes. The SEEQ analytic tool will also be enhanced, this provides detailed data analysis capabilities to time series signals and allows for complex calculations for asset health and other engineering calculations. 2025 investments will begin to improve forecasting and propensity analysis of DER adoptions. These enhancements will lead to more accurate system studies, more efficient interconnection screens and studies and better optimized designs for system improvement, non-wire alternative and loading projects. Customers will benefit from reduced interconnection study and review times and more accurate up front estimates of system upgrades.

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Interconnection Process Enablement

Q221. What is interconnection process enablement?

A221. Interconnection process enablement are investments focused on the software and interfaces for interconnection processing that includes both the interconnection portal and the interconnection database, PowerClerk. Additional investments are made in tools and interfaces to streamline interconnection processing, study and screening and benefit customers by improving the application, screening and study response times and accuracy. These investments are driven by changes to market programs, interconnection rules, procedures, and tariffs. These enhancements also streamline the process and improve the customer experience when applying for and connecting DER.

Q222. What investments were made in 2022 and 2023 and what are the benefits to customers?

A222. In 2022, the major investments implemented online payment processing for interconnection fees and enabled single login for customers, which allows them to access the interconnection portal with the same username and password as their DTEE online account. 2023 investments included improvements to PowerClerk forms, automation, website pages and documentation to support the new interconnection rules initiated in case U-20890 and implemented changes to fee structures and online payment as part of the new rules.

Some investments in this category are related to field gateway hardware as discussed in the Grid Edge Enablement section of this testimony. After 2023, the field gateway hardware investments will be split from this category to align the program with the OT investments.

Q223. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A223. Investments for 2024 include completing the payment portal changes to support the new interconnection rules and security enhancements to a single sign on login. 2024 investments include the renewal and refresh of the PowerClerk system. Enhancements in 2024 will increase automation associated to the interconnection process for small interconnections. Additionally, the enhancements include backend improvements to screening and study that will increase application throughput and reduce manual labor in preparing and running studies. Further updates and automation improvements will be done in 2025 to comply with interconnection procedures changes. The 2025 investments also aim to streamline the screening and study process and initiate the implementation of FERC 2222 related application and screening processes into PowerClerk.

<u>Hosting Capacity Enablement</u>

Q224. What are the investments in Hosting Capacity Enablement?

A224. Hosting Capacity Enablement includes improvements to the online publicly available map system that displays hosting capacity, and the capabilities to compute hosting capacity and process the data for it to be available publicly.

Q225. What investments were made in 2022 and 2023 and what are the benefits to customers?

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A225. Investments in 2022 and 2023 included publishing the initial hosting capacity map for DER and improving backend data handling to prepare updates. In 2023, the focus was on developing the loading capacity map. These maps allow customers to see the amount of remaining capacity and hosting capacity in their area.

Q226. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A226. Investments in hosting capacity for 2024 are aimed at enhancing the backend data update mechanisms of the system. In 2025, the focus will shift towards integrating the analysis capabilities, which are being developed in the load forecasting and analytics project, into the outputs of the hosting and load capacity maps. This integration will result in a more detailed representation of hosting capacity values across numerous circuit sections. The increased granularity of data will provide customers with additional information, aiding their decision-making process.

<u>Power Quality Analysis Program</u>

Q227. What is the Power Quality Analysis program?

A227. The Power Quality Analysis program are investments in software to centralize, collect, correlate, and visualize power quality data such as fault and disturbance waveforms, voltage disturbances, harmonics, flicker and momentary information from various metering sources on the system and provide analysis capabilities to help determine root cause of events and begin to establish predictive capabilities from analysis of disturbances that have not yet created an outage or equipment issue.

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Q228. What investments were made in 2022 and 2023?

A228. None, this is a new investment category in 2024.

Q229. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A229. Investments in 2024 will be to centralize power quality information into a single data set that can be analyzed and correlated with complaints, trouble events and outages. Interfaces for near real time capture of power quality meter data will be established. In 2025 analysis tools and machine learning capabilities will be added to the system to determine root cause and begin the process of identifying precursors to predict failures and outages from sensor and power quality data.

<u>Substation Design Tool Upgrades</u>

Q230. What are the investments in substation design tools?

A230. This category of investments is comprised of design and structural calculation tools that are used by engineers, planners, and designers to implement standards and calculated physical analysis into designs prior to construction. This includes new tools to facilitate rapid compliance for pole and overhead structure calculations and steel work as well as enhancement to CAD design tools to improve integration into work management, scheduling and cost estimating.

Q231. What investments were made in 2022 and 2023 and what are the benefits to customers?

A231. Investments in 2022 and 2023 included renewal of PLSCAD, a sophisticated structural design software for engineered poles and purchase of documentation editing and collaboration software for CAD designs. Other investments began the process of implementing compatible units for substation standards and structural design testing.

Q232. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A232. 2024 investments include renewal and enhancements of the Spidacalc pole design software and to acquire specialized structural modelling tools to allow for engineered structure designs to be verified. Additional structural design testing will be done in 2024 to validate the modelled parameters in the software and update design standards accordingly. 2025 will begin the process of updating the substation design tools and interfaces to utilize the compatible units and closely link design to the Maximo and supply chain process.

Distribution Planning

Q233. What is Distribution Planning (Exhibit A-12 Schedule B5.4, Page 18, line 46)?

A233. Distribution Planning is a collection of projects within the Distribution Planning OT category and represents a set of investments from the other sub programs in the Distribution Planning OT category.

Q234. What investments were made in 2022 and 2023 and what are the benefits to customers?

A234. The breakdown of significant investments are as follows:

- $98,000 of this investment to load allocation and analytics for a tool to evaluate transformer overloads and root causes, as well as a tool to understand EV adoption and how it is impacting circuit and transformer loading. This tool allows the Company to more accurately pinpoint where infrastructure needs to be updated due to DER.

- $603,000 to the load allocation and analytics project for the CYME 9.2 upgrade. This includes the license renewal and server hardware for that project. The benefits of those investments are covered in the Load allocation and analytics and Cyme Upgrade sections earlier in the testimony.
- $64,000 to the substation and structural tools budget for Bluebeam CAD markup tool for license renewals. Bluebeam CAD significantly streamlines field print markup for substation designs and reduces planning and design time.
- This line item also includes investments made to systems that support the Company's ADMS system to bring additional operational data to our employees when responding to unplanned field events resulting in better overall control and effectiveness ($8.46 million).

Q235. What investments are planned in 2024 and 2025 and what are the benefits to customers?

A235. This category will invest in small emergent needs for planning tools in 2024 and 2025 that do not clearly align to the other sub projects. Projects are selected from an existing backlog list for each investment year. These investments will either evolve into their own sub projects in the future or be incorporated into existing sub projects. Larger investments that can be clearly aligned with existing OT sub programs will be charged appropriately to eliminate the historical mixing of investment categories in this project going forward. A major investment planned for this category in 2024 and 2025 is the Circuit Reliability Optimization project.

The scope of this system is to provide a digital platform to examine and monitor every circuit for emergent events, reliability initiatives, maintenance tasks, and enhancements. It will also assess the influence of reliability programs, maintenance activities, and upgrades on the improvement of each circuit's reliability and evaluate the most effective reliability enhancement strategies, including ETTP, PTMM, Hardening, and Conversion. The system will also quantify the impact of various programs on the reliability of circuits, substations, sub-transmission, and the contribution to the overall system.

I. Work Management and Scheduling

Q236. What is Work Management and Scheduling?

A236. Work Management is a systematic approach to track and measure work as well as streamline both business processes and routine tasks. This category of investments describes the essential set of work management tools and technologies that are used to coordinate work on the distribution system, from initiation through close out of work orders, including the work steps, assignment of labor, materials, and other tasks. While current schedules and processes rely on Microsoft Excel, the benefits of automation, like drag-and-drop schedules, real-time field status updates, and integration with systems such as OMS and Maximo, are realized through these investments. Job planning, along with managing labor, material, tools, and services, is also part of the suite of tools for effective work management.

Q237. Where are the capital investment details of the projects and programs in this category?

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A237. Capital investment details of these projects and programs in this category are included in:

- Exhibit A-12, Schedule B5.4, page 17 and 18
- Exhibit A-23, Schedule M7

Table 10 Work Management and Scheduling Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Enhance Maximo Capabilities and Processes	p. 18, line 47	pp. 62-65	pp. 155-157
Primary Service Orders Replatform	p. 18, line 48	pp. 173-176	pp. 155-157
External Crew Efficiency	p. 17, line 23	pp. 66-69	pp. 155-157
Work Management and Scheduling Upgrades	p. 18, line 49	pp. 219-222	pp. 155-157
Substation Reporting and Process Enhancements	p. 17, line 20	pp. 203-206	pp. 155-157

<u>Enhance Maximo Capabilities and Processes</u>

Q238. What is Enhance Maximo Capabilities and Processes?

A238. Enhance Maximo Capabilities and Processes is a project aimed at improving and expanding the functionality of Maximo, the Company's Work and Asset Management system, and optimizing its associated processes.

Q239. What are the key drivers of Enhance Maximo Capabilities and Processes?

A239. DTEE's Work and Asset Management system, Maximo, has both on-premise and field enabled capabilities. The field portion of that system is currently filled by a field module, EZMax Mobile, that would have been replaced as part of the Maximo transformation program that is under re-evaluation. With that program now on hold the Company will invest in an upgrade of the EZMax mobile product in 2025 to ensure that users retain the ability to work effectively at the point of activity using an up-to-date product.

Q240. What are the benefits of Enhance Maximo Capabilities and Processes?

A240. This project will bring more of the capability of the existing Maximo system to the front line in the form of additional inspection forms, inspection workflows and expanded asset information. Bringing this capability to the field worker will eliminate a portion of the remaining paper-based data collection as well as ensuring that field teams have electronic access to the up-to-date equipment records when performing work making that work safer and more efficient.

<u>**Primary Service Orders Replatform**</u>

Q241. What is the Primary Service Orders (PSO) Replatform?

A241. The Primary Services Group at DTEE is responsible for working with and assisting many of the Company's largest commercial and industrial customers. To help them perform their work, a web-enabled tracking system that houses primary customer information is used. In addition to being an important tool for the Primary Services Group, other departments such as Regional Relations, MAS, and the Relay Group use this system when working with or for these customers.

The PSO Replatform project is a 3-year investment beginning in 2024 with a targeted completion in 2026. The scope of the project has 4 major components:

- Upgrade existing end-of-life primary services web-enabled system.

- Capture and maintain detailed customer information and electronic primary operating orders.
- Digitize and archive the primary customer infrastructure as-builts and sketches.
- Build interfaces between the new application and supporting systems, such as customer relationship management, enterprise asset management and mapping systems.

Q242. What are the key drivers of PSO Replatform?

A242. Today there are three separate systems required to fully support these functions. The PSO Replatform project will combine all the existing systems into one consolidated system and provide automated connections to other systems that today are not connected. This new system, when fully implemented, will connect with other customer facing systems such as the customer relationship management (CRM), enterprise asset management (Maximo) and mapping systems (ESRI). The current primary services application requires extensive manual processing and data entry, resulting in productivity loss and an inability to keep up with increasing demand. This negatively impacts the customer experience and level of service DTEE can provide.

Q243. What are the benefits of PSO Replatform?

A243. The goal of this project is to create a single system that houses primary customer information and equipment needed to isolate customers from DTE Electrical system and vice versa. This system will provide support to field resources with quick access to customer infrastructure and eventual connectivity to ESRI, Maximo & CRM with up-to-date information needed to effectively support primary customer needs. Customers will receive better and faster service and employees will be able to effectively handle more requests faster.

External Crew Efficiency

Q244. What is External Crew Efficiency?

A244. External Crew Efficiency is a category of capital investments targeted at the efficient and cost-effective use of external contract crews used to augment Company crews. The capability to utilize external crews efficiently and cost-effectively is a key component to improving the speed and efficiency of storm restoration. The primary investment in this category is the Utility Restoration Management Application (URMA).

Q245. What is URMA?

A245. URMA is an application that will manage crew rosters for external contract crews, track current jobs status and work completed in the field, while enabling visibility into contractor productivity and payment.

Q246. What are the key drivers of the URMA application?

A246. The Company relies heavily on external contract crews to support restoration efforts when there is a significant event on the grid, especially during major weather events. As the Company works to improve restoration for customers during storms the command, control and logistics associated with the deployment of those crews has never been more critical. Currently the Company lacks visibility into work performed by non-DTE contract crews and cannot easily measure productivity for these crews. Additionally, the rosters submitted for these crews are not standardized, many being excel files that are submitted individually, making it challenging to easily view and analyze rosters for all crews. In order to reduce waste and improve productivity, ultimately leading to faster storm restoration, the Company needs improved visibility and monitoring over these crews.

Q247. What is the scope of the URMA application?

A247. This is a multi-year project that began in June of 2023 with the first implementation occurring in February of 2024. Delivered in that first implementation was an end-to-end crew rostering application. The rostering application standardizes qualified crew make up and the equipment used at the job site by external contract crews, enabling operational control and the development of cost benchmarking to assist in continuing to reduce overall cost per outage event.

The next set of investments for 2024 and 2025 are planned to include:

- Mobile application expansions that will status and ensure workflows for all assigned work.
- A work completed input form that will document all material used, actual work completed by teams in the field, give visibility on work mix, and validate invoices from external contract crews.
- Expand rostering capabilities to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessors to deploy these teams efficiently and accurately.
- Expand the use of the electronic mobile work application to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessors.

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- Expand the use of the work completed input form to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessor.
- Deliver a billing app to document contractor time entries, validate work assignments, and expedite accurate invoicing.

Productivity improvements for outages include:

- Enhanced functionality in URMA will allow external contract crews to have quick electronic access to job specific information (maps, assignments, chronology), driving improvements on patrol and restoration times.
- Real time job status and updates on work required will allow the Emergency Field Leaders and Regional Incident Command to take quick action to manage crews more effectively.
- Clear line of sight into crew make-up and available equipment will inform resource assignment and optimization.
- Right-crew to the right job: Contractor resources are currently not optimized across restoration work type (i.e., too many contractors on smaller jobs or spending too much time on the job). Using Single outage jobs as an example, most jobs require only 2 crew members and should be completed in less than 2 hours.

Q248. What are the benefits of the URMA application?

A248. Currently, much of the coordination with external contract crews is manual process-based and not system-enabled. This can lead to gaps in timely visibility into work performed in the field, challenges with the ability to measure foreign and contractor crew productivity, and overall control of those resources in real-time. These challenges are further exacerbated during major storms. The benefits of URMA include: reduction of waste through improved quality controls and crew validation; improved ability to monitor and audit contractor invoicing to ensure accuracy; and improved visibility of contract crew work scope and real time job statues. The crew rostering application supports the reduction of waste and improved auditing of contractor invoicing by providing visibility, validation and verification of crew pay rates, crew sizes, and equipment utilized per job. The improved visibility of contract crew work scope and real time job statuses provides the Company leadership increased oversight and ability to monitor performance and drive productivity real time during storm restoration. Additionally, URMA provides more efficient communication of contract crew work assignments directly to the crews, reducing wait time for crews to receive work assignments, and allows contract crews to access job specific information electronically, improving restoration time. The Company has estimated these improvements will drive efficiencies and productivity in storm restoration efforts, reducing the average storm duration by three hours.

<u>Work Management and Scheduling Upgrades</u>

Q249. What Work Management & Scheduling upgrade investments were made in 2022 and 2023?

A249. Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2, Contract Agreement System (CAP) Replacement, Maximo Application Suite Upgrade Phase 1 sponsored by Company Witness Sharma, Crew Management Enhancements (2022/2023), multi-year renewal license purchase for ARCOS

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operator call out application, PMO Primavera upgrade and field operations tools automation are the investments made in 2022 and 2023.

Q250. What is the Type 2 Customer Communication & Process Efficiency Closed Loop project?

A250. The Type 2 Customer Communication & Process Efficiency – Closed Loop project included the development of a new application designed to track customer type 2 damage claim interactions, instances where customers file a claim that the Company damaged their property while performing work. The new application was initiated to improve claim management, communication with customers regarding their claim, and reduce overall process cycle time for customers.

Q251. What are the key drivers of Type 2 Customer Communication & Process Efficiency?

A251. The Damage Claims group historically utilized multiple systems, or tools such as Excel, to manage damage claims and communicate updates to customers. These systems were not integrated, nor did they provide visibility to all key stakeholders and customers. The cycle time to resolve damage claims was on average 60-90 days, and there was no automated way to send customers standard updates throughout the process and when claims were closed. Additionally, when customers called into the DTEE call center, the call center representative did not have visibility into a claim status and could not provide the customer information regarding a claim. As a result, the Company received complaints from customers about the damage claims process.

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Q252. What are the benefits of Type 2 Customer Communication & Process Efficiency?

A252. With the completion of this project claims are tracked and processed centrally through the new application which includes all case information and is integrated in the Company's customer relationship management system (CRM). This includes a validation tool for customers to confirm their claims have been submitted, a feedback loop for customers once claims have been resolved, and a one stop repository for both active and resolved claims. This investment improved the response time for damage claims resolution, with the average response time dropping from an average of 60-90 days down to 23 days in 2023. Additionally, this system is integrated with the Company's CRM, which allows customer service representatives in the call center to see claim statuses and provide customers updates as requested. This investment also enabled the Company to automatically send weekly communications to customers regarding claim status updates and a communication when a claim has been resolved through various methods such as letters, texts and calls. In 2023, 100% of customers that filed a claim were communicated to upon claim resolution.

Q253. What is the Contract Agreement System (CAP) Replacement?

A253. In 2022 the Company began a project to replace the existing Contract Agreement System (CAP). That system was an internally created program which was no longer meeting the needs of the business unit. The system did not have the capability to easily create new agreement types and had no electronic document signing or interchange mechanisms.

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Q254. What are the key drivers of CAP Replacement?

A254. The Company enters into over $3 million dollars a year in contracts for new business and construction/service work. The current system is limited in the information it provides and inefficient, it does not include automated workflow for timing, nor does it have alerts to assist the contracts team in understanding when any step in the process has taken longer than expected to complete. This can result in extended construction service times and negatively impact customers that are attempting to have services performed by the company on their behalf.

Q255. What are the benefits of CAP Replacement?

A255. This system helps the Company remain compliant with service levels related to timing for new business and construction/service work for customers. In addition, it provides the flexibility to create new types of agreements, allows more rapid process improvements more easily than the previous system, and has improved worksheet operability covering 15 electric service and construction agreements. For customers, this translates into more efficient contract approval, a simplified electronic routing processes for document management and leverages DOCUSIGN for electronic signature to improve the customer experience.

Q256. What is Crew Management Enhancement?

A256. Crew Management Enhancement is a Crew Rostering system for DTEE crews that replaced the outdated Crew Rostering system and will be integrated into the URMA application as it goes into service. This is crucial for the Company's operational groups to effectively build, manage, and deploy crews while adhering to union

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agreements and maintaining DTEE's commitment to safe, timely, and qualified service.

Q257. What are the key drivers of Crew Management Enhancement?

A257. DTEE employs processes and systems for resource management of internal DTEE crews. The two-year project brought significant improvements, including infrastructure updates, enhanced crew visibility, automated tracking of overtime and training, adjustments for union contracts, and the integration of apprentice rostering without manual intervention. Additional enhancements in 2024 and 2025 is part of the External crew efficiency project.

Q258. What are the benefits of Crew Management Enhancement?

A258. The capacity to efficiently roster and deploy crews ensures that work can be accomplished with greater safety and speed.

In 2022, the system transitioned to new infrastructure, improving performance, and features such as visible crew resources, automated overtime and training tracking, and integration of vacation calendars were introduced. A visual dashboard increased crew availability visibility, and record-keeping for employee OT scheduling improved.

Continuing into 2023, continuous improvement led to additional enhancements, a dedicated training environment, adaptability to changes in union contracts, Fleet Organization integration for calendaring and OT reporting, and expanded management-level reporting. The introduction of a training environment allowed

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users to train on the rostering system beyond initial introductory training. With the ability to effectively roster and deploy crews, work will be done more safely and quickly.

Q259. What is PMO P6 Primavera Refresh project?

A259. PMO P6 Primavera Refresh project is an upgrade from the current unsupported version of Primavera Scheduler used by DO Scheduling and DO PMO Groups to the newest version of Primavera. In addition, the project includes the replacement of the current WTA (Walter Tanner & Associates) interface between Primavera and Maximo with an industry standard product called Maxavera.

Q260. What are the key drivers of PMO P6 Primavera Refresh?

A260. Primavera is the scheduling software used by DTEE's DO Scheduling and PMO Groups to manage and execute the entire DO strategic capital investment. The current version of Primavera used by DO Scheduling and PMO was 16 major revisions behind and unsupported by the vendor. If the software were to crash, DO Scheduling and PMO would lose the ability to manage the DO strategic capital portfolio, affecting critical capital investments in the grid.

Q261. What are the benefits of PMO P6 Primavera Refresh?

A261. The upgraded Primavera version (and Maxavera interface product) will eliminate data latency that is currently present with the Primavera and Maximo systems and provide a more robust application. It will also bring the DO PMO group to the same version of the scheduling product as the corporate project management office is using allowing fee exchange and interoperability of schedules across all DTEE.

Q262. What is the Multi-year Renewal license purchase for ARCOS?

A262. DTEE has utilized the ARCOS Callout solution for several years, necessitating frequent license renewals. Recently, the company successfully negotiated a comprehensive 5-year agreement during the latest renewal, preventing year-over-year cost increases and ensuring elevated warranty support throughout the period.

Q263. What are the key drivers of Multi-year Renewal license for ARCOS?

A263. The ARCOS license was expiring, and the Company was facing potential cost increase for future licenses. This system is crucial for the Substations group to conduct after-hours callouts while adhering to collective bargaining agreements and union rules.

Q264. What are the benefits of Multi-year Renewal license for ARCOS?

A264. This investment ensures the continuity of an operational callout system, maintaining efficiency and reliability in managing after-hours dispatching for the substations group. By negotiating a 5-year agreement the company was able to reduce future cost increases for licenses and obtain elevated warranty support.

The ARCOS system itself enables timely and accurate job callouts, reducing response times for substations employees to respond emergent issues on the grid.

Q265. What is Field Operations Tools Automation?

A265. Field Operations Tools Automation is an investment undertaken to replace existing operational tools, applications and dashboards that perform important operational control functions but that no longer have the capability to support DTEE's rapidly evolving operational processes. Some DO apps use extremely old technology and utilize on-premises servers. These apps are built on 20-year-old foundations, such as classic ASP and PHP, which substantially increases maintenance cost. The objective is to automate manual efforts and reduce reliance on managing operations through excel spreadsheets.

In 2023, a project to develop a system for use in confirming Customer Power Status, particularly in-line with restoration efforts was in place. The project created a facility to visualize the power status of meters at Customer sites along with the state of the communications devices necessary to backhaul the data to DTE. This utility gives insights to analysts tasked with determining why the current power state at a customer site is unknown and facilitates detection of nested outages or field communication devices that may need repair.

Q266. What are the key drivers of Field Operations Tools Automation?

A266. As the Company continues to work to improve its operations both in normal weather conditions and during increasingly frequent weather events it continues to rely upon both departmental applications and internally built solutions. Many of these solutions do not scale and are not serving current or emerging needs adequately. Several systems that measure day-to-day performance are dependent on manual steps and do not have a consistent approach to data management. Report generation is not consistent between groups/regions/service centers. This leads to process inefficiencies and reduces situational awareness. The Field Operations Tools Automation project was undertaken to begin to select the most important of these use cases and automate them in an effective and supportable manner.

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Increasing automation in these activities will increase visibility into process adherence, help better identify gaps and improve situational awareness.

Q267. What are the benefits of Field Operations Tools Automation?

A267. For customers, this investment will result in tighter control of field events, more information in the hands of crews to be shared with customers at their work locations and improved response and restoration times during outage events. Employees will be able to minimize usage of and reliance upon cumbersome manual processes, add new opportunities to collaborate when reviewing/ sharing/ editing, and tracking activities. Instances of duplicative effort and human error will be reduced. Team members can focus on value-add versus manual activities.

The 2023 efforts around CPS facilitated faster detection of on-going electric service and communication network issues that can impact a customer's service restoration and timely notifications. It was important to undertake the project in the time frame it was executed to provide supporting insights to the larger Customer Power Status Visualization (CPSV) program efforts designed to improve DTEE's outage detection and service restoration efforts.

Q268. What are the new investments planned for 2024 and 2025 in the Work Management & Scheduling upgrade category?

A268. The planned investments in the work Management & Scheduling upgrade category for 2024 and 2025 are: Circuit ownership app, Wiredown Associated Call Enhancement, and moving Mobile timesheet (MTS) Data to cloud.

- Circuit Ownership application:

The Circuit Ownership App is a new tool that consolidates data to a central location for the Circuit Owner's comprehensive review. This data encompasses AMI Meter Data, SCADA Data, Circuit Maps, current Maximo Work Orders in the field, and Damage Assessment Information.

The new tool will facilitate a centralized contact accountable for real-time circuit performance, strategizing, and advocating for the circuits. This strategy may involve both short-term reliability projects (completed in under a year) and extensive multi-year reliability projects.

The identified benefits include a streamlined process, reducing engineers' time navigating various systems, resulting in quicker analysis and decision-making for service-affecting issues on the circuits they oversee.

- Wiredown Associated Call Enhancement:

The company frequently receives redundant reports of wires down in the field, resulting in the creation of multiple jobs in OMS. This causes delays and unnecessary truck rolls.

The Wiredown Associated Call Enhancement investment involves updating the OMS to efficiently link wiredown jobs, reducing wasted truck rolls and enhancing productivity. The Field Service Edge application will be modified to display associated calls on a job, enabling crews to access necessary data for safe evaluation of wire down incidents and addressing public safety concerns. This enhancement aims to streamline and enhance the efficiency of wiredown job responses.

- Moving mobile time sheet (MTS) data to Cloud:

Presently, the Company can observe general time sheet charges and manually delve into specifics for OH/UG crews for an event requiring a truck roll.

The new cloud-based data will allow the OH/UG teams to automate reports on detailed crew time charges, enhancing our understanding of defect codes like wait time. Utilizing the cloud data platform will integrate disparate sources, such as Mobile Timesheet charges and Outage Management events, enabling automated reporting dashboards for timely field productivity visibility.

The implementation of this system can eliminate approximately 2 hours of daily manual work for four individuals, equivalent to a full-time Operations Analyst position worth $80,000 per year. This will not completely offset the position, but provides an opportunity for more productive and analytical tasks. Additionally, it increases the capacity to run reports for all Service Centers, saving time and identifying opportunities to enhance field productivity, both in storm and non-storm scenarios.

J. Asset Management

Q269. What is Asset Management?

A269. Asset Management is a category of investments that involve utilizing technology to support effective asset management. These investments include projects that support managing physical assets, such as personal protective gear and large fleet vehicles, as well as projects that support electronic asset data management.

Q270. Where are the capital investment details of the projects and programs in this category?

A270. Capital investment details of these projects and programs in this category are included in:

- Exhibit A-12, Schedule B5.4, page 17-18
- Exhibit A-23, Schedule M7

Table 11 Asset Management Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Systematic Tracking of Rotatable Assets	p. 17, line 22	pp. 207-210	pp. 157-159
Asset Management Upgrades	p. 17, line 21	pp. 21-24	pp. 157-159

<u>Systematic Tracking of Rotatable Assets</u>

Q271. What is the Systematic Tracking of Rotatable Assets?

A271. This new investment in 2025 includes developing and implementing a digital tracking repository for items like personal protective equipment that have expiration dates and must be managed through their deployed life cycles. It improves the accuracy, efficiency, and accountability on the movement of materials within a process. Examples include Field tracking of assets using RFID (radio frequency identification trackers) readers on trucks, in warehouses and tracking rubber goods (sleeves and gloves used by line workers) for front line employees. Benefits include decreasing the risk of having outdated assets in the field, and improving the accuracy, efficiency, and accountability on the movement of materials within a process.

Q272. What are the key drivers of Systematic Tracking of Rotatable Assets?

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A272. Field tracking of assets that must be rotated in and out of the field on a regular cadence and the record keeping needed to ensure that none of them remain deployed beyond their expiration date is a key and critical component of DTEE's overall safety program. Prior to this investment, these assets were being tracked manually. A practice subject to human performance or tracking errors.

Q273. What are the benefits of Systematic Tracking of Rotatable Assets?

A273. Ensuring that all PPE is current and safe to use will reduce the likelihood of injury to workers, a core value of the Company.

Asset Management Upgrades

Q274. What is the Brigade 360 Cameras Project?

A274. The Brigade 360 cameras project was an investment specifically undertaken to reduce the occurrence of motor vehicle accidents and improve crew and facility safety. This included installing 360-degree cameras on Distribution Operations vehicles. These cameras provide additional views that allow drivers to see aerial equipment hazards.

Q275. What are the key drivers of the Brigade 360 Cameras Project?

A275. DTEE's bucket and digger trucks represent a significant investment on the road, and due to their size and driver visibility have some inherent challenges with impacts of low hanging tree limbs, awnings, etc. Safeguarding these assets and ensuring their operational efficiency is crucial for success, especially when considering the limited availability of trucks in the overall market. This technology investment provides for both real-time and recorded imagery for crews and allows them to operate their vehicles with more situational awareness and higher levels of safety. Between 2022 and 2023, 550 heavy-duty vehicles, 37 medium-duty vehicles, and 69 light-duty vehicles were fitted with the Brigade 360 cameras. Approximately 60 bucket trucks and 250 light trucks in the fleet are awaiting fitting of the system.

Q276. What are the benefits of the Brigade 360 Cameras Project?

A276. Impacts with tree limbs and overhead structures happens typically more than a dozen times per year and can cost as much as $3,500 each time to repair the bucket and other parts of the vehicle**.**

The Company made this investment with the goal of decreasing motor vehicle incidents, measured by the Collisions per Million Miles (CPMM) metric. Since inception, motor vehicle accidents have decreased from 140 (2022) to 119 (2023), marking a 17% improvement. It's crucial to note that factors like inclement weather and road conditions affect this metric, and this investment is part of a broader effort to enhance vehicle safety. Lowering vehicle incidents not only enhances public safety but also reduces expenses associated with repairing or replacing damages, contributing to overall affordability of products.

K. Mobile Technology

Q277. What is Mobile Technology?

A277. Mobile Technology is a category of investments focused on creating seamless transitions between on-line and off-line operations and provide integrated communication, including workflows, between the control room, field leaders, field crews, and supporting organizations. Mobile capabilities include both devices and applications that are engineered for mobile access and usage. Applications include dispatch, work execution and forms digitization, location tracking, route navigation, analytics, and secure file sharing.

Q278. Where are the capital investment details of the projects and programs in this category?

A278. Capital investment details of these projects and programs in this category are included in:

- Exhibit A-12, Schedule B5.4, page 17-18
- Exhibit A-23, Schedule M7

Table 12 Mobile Technology Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Mobile Tools Expansion	p. 18, line 50	pp. 116-119	pp. 133, 159-161
Maintain Compliance	p. 18, line 51	pp. 96-99	pp. 133, 159-161
Enhance and Expand Cybersecurity	p. 18, line 52	pp. 58-61	pp. 133, 159-161
Mobile Equipment Replacement	p. 18, line 53	pp. 108-111	pp. 133, 159-161
Mobile Technology	p. 18, line 54	pp. 112-115	pp. 133, 159-161

<u>Mobile Tools Expansion</u>

Q279. What is Mobile Tools Expansion?

A279. Mobile Tools Expansion is a category of investments related to tools and applications utilized by field resources. Mobile tools are a critical investment to support operational crews and leadership drive efficiency, productivity, and safety. The primary investment in this category is the Every Day Daily Plan (EDDP).

Q280. What is Every Day Daily Plan (EDDP)?

A280. The Everyday Daily Plan is a web application designed to serve as a consistent "all-weather" tool for both storm and non-storm scenarios. This tool facilitates the Company's response to planned and trouble work on the electric system, utilizing real-time data to bundle and prioritize jobs. Customizable inputs allow for the escalation of variable customer needs, such as Election Day Polling Locations and School Count Day. The EDDD will work in tandem with an auto-assign function, driving optimization of job and crew dispatch for the first job of the day.

Q281. What are the key drivers of EDDP?

A281. After the 2023 catastrophic ice storm the Company undertook a series of actions to take advantage of system capabilities and opportunities that were never possible prior to the replacement of the outdated OMS system in February of 2023. The lessons learned during that storm and the capabilities that the new systems offered allowed DTEE to explore opportunities within its mobile tools, which will ultimately dramatically transform the ability to serve customers quickly and safely as power is restored after significant storm events. This EDDP was begun as one of multiple ways that DTEE will bring new capability to field teams. Historically, planning and prioritizing work for the day involves using multiple databases, human performance for priority evaluation, and manual phone calls. Additionally, the prioritization and bundling of work during a storm utilized different tools than normal operations day to day work. During storm situations a team of five

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individuals worked 16 hour shifts through the night manually developing a storm restoration plan for the next day. Also, during storm and during normal operations the first job a crew received was manually dispatched to the crews, at times causing delays for crews getting to their first job of the day, especially during high event days and storms. The EDDP enables the automation of several processes, such as prioritization, bundling and auto-assigning work of work, reducing manual work and driving efficiency. This ultimately improves crew efficiency and enables crews to get to their first job quicker, reducing restoration time for customers.

Q282. What are the benefits of EDDP?

A282. The EDDP streamlines storm and normal operations daily planning processes, creating one standard process used during all weather events. This tool automates daily work prioritization, budling and dispatching of the first event of the day to crews in the field. The automation of this work reduces manual labor and individual decision making, drives efficiency through bundling of work and geographically routing, and improves restoration efforts through faster dispatching of jobs in the morning. The tool will seamlessly integrate all crews, of all types, into flexible and timely daily plans. The EDDP will reduce an average one hour a day per crew in wait time for their first job of the day, increasing productivity and reducing restoration time for customers.

<u>Maintain Compliance</u>

Q283. What is Maintain Compliance?

A283. DTE Electric is subject to multiple regulatory authorities and must maintain compliance with the MPSC, FERC, NERC and other industry regulations and

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orders. The level of regulatory and industry oversite has grown to the point that a program is being undertaken to ensure successful compliance. This investment is expected to grow year-over-year, especially beyond 2025 when the Company anticipates the need for additional compliance components to be required on several topics including but not limited to energy justice (EJ), electrification, cyber security and expanding NERC requirements. Having access to accurate, timely and complete operational data is key for compliance. System investments to compile day-to-day operational information and demonstrate compliance are needed to replace labor intensive manual methods that have been used to date.

Q284. What are the key drivers of Maintain Compliance?

A284. Real-time operational data enables DTEE to adapt to changing regulations and demonstrate adherence to those changes. Investing in compliance automation to meet new demands and having data accessible in a timely and cost-effective manner for reporting are some examples as to why this investment is prudent.

Q285. What are the benefits of Maintain Compliance?

A285. Like any other industry the Company stewards a body of sensitive data required for effective operations. This data includes electrical system, operational, customer, and payment data. Many regulations and compliance mandates govern the Company's use of this information and how it must be safeguarded. DTEE's customers benefit from this investment when the information is collected, used, and secured in such a way that the information is safeguarded both within Company facilities and when in the hands of DTEE employees while serving the customer at their location. Employees benefit by having ready access to the information needed to serve wherever the work requires, knowing that mobile systems comply with all the regulations that govern their job functions.

<u>Enhance and Expand Cybersecurity</u>

Q286. What is Enhance and Expand Cybersecurity?

A286. The Company plans to invest hundreds of millions of dollars in its grid automation programs over the next decade. The automation that is placed in the field to enable that automation and control must be protected from cyber-attack and that protection presents unique and ever evolving challenges as bad actors will recognize this field automation as a potential that they will look to exploit. This project is designed to place targeted technologies, both hardware and software, into the Company's infrastructure in a controlled manner to test and evaluate the most effective ways to address these threats.

Q287. What are the key drivers of Enhance and Expand Cybersecurity?

A287. Industry-wide there is recognition both for the need to automate the ever evolving and more complicated grid to control it in real-time and that this automation will create potential vulnerabilities for outsiders to exploit. If these potential threats are not addressed early in automation programs, then the opposition will gain a significant advantage over the Company's ability to safely operate the grid. This program will assess the cybersecurity needs for this infrastructure and inform the selection of tools and techniques to combat these threats.

Q288. What are the benefits of Enhance and Expand Cybersecurity?

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A288. Adequately understood and implemented tools and countermeasures will serve to ensure that the grid is as reliable, available, and defensible as possible. Customers will benefit from a more resilient, more effectively run grid, while at the same time this project will be foundational in ensuring that only the authorized operators are able to access and control the automation that is put in place. This is critical from both a safety and an operational standpoint.

Mobile Equipment Replacement

Q289. What is Mobile Equipment Replacement?

A289. The Company has thousands of mobile devices that have been deployed to front-line workers and their leadership. These devices have planned useful deployed lifecycles of 6 years. The Company plans and executes device replacements yearly on ~1/6th of those devices to keep the devices operational and secure.

Q290. What are the key drivers of Mobile Equipment Replacement?

A290. Up to date devices are more reliable and technically secure from cyber threats than older, less capable equipment. It is important for field workers to have operational and up-to-date equipment to perform their work functions safely and effectively.

Q291. What are the benefits of Mobile Equipment Replacement?

A291. Correctly functioning equipment running effectively, and up-to-date systems contribute to efficient processes and work completion, an advantage to customers in terms of DTEE's ability to be responsive to their needs and helps shorten outage restoration times.

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Mobile Technology

Q292. Why has the Company chosen to represent its Mobile Technology spend more specifically in this rate case?

A292. In previous rate cases, Mobile Technology was represented in the financial exhibit as the sum of several included projects and talked about at that higher level. Feedback from the commission and the types of discovery questions from intervenors indicate that a more itemized approach was desired so for this case that category has been reworked to itemize its key investments.

Q293. What were the key investments made in 2022 and 2023 that are Mobile Technology?

A293. The key investments grouped under the heading of Mobile Technology were Outage Status App Changes for Damage Assessment, Tree Trim's Vegetation Management Software Replacement Pilot Project, Service Center Wi-Fi Upgrades, Lemur Pro Multiyear License Purchase and Field Service Edge Overhead (OH)/Underground (UG) Enhancements.

Q294. What is Outage Status App Changes for Damage Assessment?

A294. The scope of this project was to create a capability within the Outage Status Application (OSA), the mobile storm tool used by DTEE's tree trim and all foreign crews for storm response, allowing automated near real time access to update damage assessment from the field to planning staff.

Q295. What are the key drivers of Outage Status App Changes for Damage Assessment?

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A295. Over the last several years the amount and severity of damage caused by storm events has increased as weather in Michigan changes for the worse. It is critical that damage assessment teams get into the field and get their data back to planning staffs as rapidly as possible immediately following an event. get. This project adds damage assessment capability to one of DTEE's key field tools that it previously did not incorporate. With the inclusion of this capability, the automated damage assessment form is accessible by all damage assessors to record and provide information on outage events with this information flowing into the OMS system in real time as the form is completed and sent electronically.

Q296. What are the benefits of Outage Status App Changes for Damage Assessment?

A296. Having damage assessment data rapidly available allows the Company to plan restoration work more accurately for any given outage event. This information provides crews with advance knowledge about what types and quantities of materials they may need due to the assessor's detailing of the actual location and severity of the damage that has occurred. This benefits the customer in faster restoration times and more accurate estimates. It also advantages the Company's employees as advance notice of this kind improves the safety of the workers and the efficiency of logistic response at the point of damage. A final benefit comes from use of the damages assessment data to predict the needs for future events. Where this data is available, it can be used to model future events and improve work standards and processes. If damage levels in advance of an incoming event can be better predicted, then the ability to have the right number of resources deployed at the right locations will continue to improve response times, repair effectiveness, and overall cost per event.

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Q297. What is Tree Trim's Vegetation Management Software Replacement Pilot Project?

A297. The Company's existing Vegetation Management system is approaching end of life and will need to be replaced within the next 3-4 years. This pilot project is a key component in selecting an appropriate replacement that will fulfill the business outcomes needed for achieving and maintaining a 100% on cycle trimming program and helping to move the Company to predictive on demand vegetation management.

Q298. What are the key drivers of Tree Trim's Vegetation Management Software Replacement Pilot Project?

A298. The replacement of DTEE's existing Vegetation Management tool will be a multiyear, multi-million-dollar investment. The Company solicited multiple companies through a formal RFP and selected an initial preferred partner. To verify this selection a pilot project was undertaken to demonstrate the capabilities of that selected software to further validate the selection before accepting the final statement of work for the larger program. The activities within the pilot will allow the team to experience firsthand the software, participate in configurations based on key business requirements, experience onsite training, perform device setup, engage in ongoing Q&A and evaluate vendor support throughout pilot program. All these activities will validate the front runner's solution in the Company's environment and shorten overall implementation of a final product. Choosing a vendor without piloting the software beforehand may lead to receiving a product that does not meet expectations.

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Q299. What are the benefits of Tree Trim's Vegetation Management Software Replacement Pilot Project?

A299. The pilot program is a key piece in evaluation of a potential work management software replacement for Tree Trim. The pilot will highlight key business functionality requirements for field and back-office users, with the goal of finding and addressing any functionality discrepancies between the RFP requirements and the actual vendor product prior to the beginning of the project.

Q300. What is the scope of the Service Center Wi-Fi Upgrades?

A300. The project scope was to upgrade current Wi-Fi Infrastructure at all Service Centers including Warren and the Technical Development center (TDC). It included installation of additional Wi-Fi capacity / coverage. With increase of over 100% in the number of mobile devices in use by teams at decentralized locations (MDTs, laptops, tablets, and phones) and the increase in the size of the area that had to be covered at each location, the existing Wi-Fi footprint and capacity had to be increased. Addressed coverage issues inside the building and reconfigured existing layout to meet updated requirements. The project also added outdoor coverage in the parking areas, truck bays and garages.

Q301. What are the key drivers of Service Center Wi-Fi Upgrades?

A301. Service Center demand on Wi-Fi has increased over time. Existing capacity and area of coverage was no longer sufficient to support the increased usage of mobile devices like MDTs, laptops, tablets, and phones. It became necessary to increase indoor and outdoor Wi-Fi capacity and coverage at 15 locations (13 Service Centers, Warren Center and the TDC.) Field personnel will be able to connect to

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proper applications and will have appropriate bandwidth to run applications and obtain data on the network.

Q302. What are the benefits of Service Center Wi-Fi Upgrades?

A302. With this investment employees will be able to use their mobile tools anywhere on service center property to transfer data and software updates. The original Wi-Fi designs at these locations were built with the assumption that any data intensive transfers (e.g., maps, software patches, and operating system updates) to mobile devices would be accomplished through a wired interface with only. This limited how often and how time consuming these transfers were, which in turn limited the number of changes that were made. As business needs have evolved and the frequency of these activities has increased a different solution was needed. As a result, the process for these activities went from monthly or quarterly wired updates to on demand wireless ones. This is now possible as this technology has matured, and its capabilities have improved. Wireless has the capacity to deliver large updates and handle hundreds of connections over longer distances.

Q303. What is Lemur Pro License Purchase and why is it necessary to have these licenses?

A303. Purchase of 3-year Lemur Pro license renewal was completed in 2023. Lemur Pro, from Locana, is the application used by the OH/UG/PSR field resources to access the As-Built maps of the electrical system. It provides access to the maps and equipment attribute information in both connected and disconnected/offline conditions. Crews can see the location of their work in relation to circuits and other equipment as well as the location of other crews and contractors.

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Q304. What are the key drivers of Lemur Pro License Purchase?

A304. By purchasing a 3-year license agreement with Locana the Company, and by extension the customers, can be protected From unanticipated price increases and by ensuring the level of warranty support that is provided by DTEE's vendor partner.

Q305. What are the benefits of Lemur Pro License Purchase?

A305. Cost containment and Warranty support inclusion are the main benefits of this investment.

Q306. What is Field Service Edge (FSE) for Overhead and Underground crews?

A306. Field Service Edge (FSE) was deployed in Feb 2023 for electric field operations and Overhead (OH) and Underground (UG) crews. The FSE mobile application is being used to allow OH/UG field resources to receive trouble job assignments and details associated with those jobs. At the initial launch, the Company had implemented the same feature set that was originally planned for the Compass mobile tool before Compass was retimed to after go-live. Once in place and in use it was determined that this tool could enable additional features that would contribute to improved storm restoration efforts.

Q307. What are the key drivers of FSE for OH/UG?

A307. After the catastrophic ice storm in February of 2023 the Company focused on improving storm restoration processes. Adding additional capability to the primary field tool was determined to be an important investment. This led to a series of enhancements to the system based on storm improvement efforts and feedback from

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the field and dispatch teams on improvements to the usability of the FSE mobile app.

Some of the Field Service Edge (FSE) enhancements that were deployed to the overhead/underground field crews in 2023 include:

- Consolidated input screens: Changes in how field crews will handle accelerated storm restoration led to an opportunity to consolidate some of the input screens that the crews interact with and ensures that all of them most important information in a simplified workflow.
- Added an assignment prioritization grid view that closely mimics that same functionality at a dispatchers station in the OMS. This view now highlights priority jobs, allows sorting and filtering to help crews focus during storms rather than a first in first out flow that was typical of the original product delivery.
- Implemented bulk updates and quick completions for common issues.
- Added the ability to view all the crew's current assignments on a map to assist in geographically tracing wire downs and circuit issues. This type of analysis function was previously found at the dispatch level, but this allows movement of that awareness and decisioning to the point of activity.
- Simplified the meter exchange job flow and allowed bar code scanning for serial numbers to accomplish routine tasks often associated more rapidly with restorations.
- Added link to report of all crews working on the same circuit to help with situational awareness.
- Improve data quality by enabling required functionality for specific data fields and formatting of data being sent back to OMS.

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Q308. What are the benefits of FSE for OH/UG?

A308. The above-described enhancements to workflows and screen consolidations have been implemented, all of which are integral components to improve storm restoration efforts.

Q309. Does this complete your direct testimony?

A309. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL J. HATSIOS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL J. HATSIOS

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Michael J. Hatsios (he/him/his), and my business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed as Director - Customer Service Operations by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric, DTE, or Company).

Q3. What is your educational background?

A3. I earned a bachelor's degree in mechanical engineering from Lawrence Technological University in Southfield, MI, and a master's degree in business administration from the University of Michigan's Ross School of Business, Ann Arbor, MI.

Q4. What work experience do you have?

A4. Prior to joining DTE, I was employed in various roles as a design and manufacturing engineer for Ford Motor Company and Visteon Automotive. I joined DTE in 2001, and since then I have held positions of increasing responsibility in our non-regulated subsidiaries, Treasury, the Controller's Office, Fossil Generation, Enterprise Performance Management (EPM), and Customer Service.

Q5. What are your current duties and responsibilities?

A5. Currently, I am a Director in the Customer Service organization, where I serve as the Chief of Staff for the Senior Vice President of Customer Service. In this role, I am responsible for the Annual Planning Cycle (APC), Customer Research, Data Analytics, and the Customer Service IT Capital, and Customer Service O&M, portions of DTE Electric and DTE Gas rate case filings.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following case:

U-21087	Voluntary PrePay Billing Program
U-21297	DTE Electric Company 2023 General Rate Case
U-21291	DTE Gas Company 2024 General Rate Case

Part 1. Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Describe and support the Company's Customer Service IT Portfolio and capital investment in the following IT Investment Categories: Regulatory/Compliance, IT Enhancements, and Strategic.
- Support the reasonableness and prudency of capital expenditures for applicable projects within DTE Electric's Customer Service IT Portfolio in the amount of $62.1 million for the historical test year ended December 31, 2022, $74.6 million in the bridge period (for the 24 months ending December 31, 2024), and $33.0 million for the projected test year period ending December 31, 2025. My

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testimony describes, among other things, how these projects improve operational efficiencies, reduce operating costs, enhance customer interactions, increase customer access to information, satisfy regulatory and compliance requirements, and create opportunities for more customers to voluntarily participate in the expansion of the Company's renewable energy portfolio.

- Provide details supporting the Company's request for cost recovery of $11.4 million in historical capital investments related to digital self-service projects and a portion of the Advanced Analytics Use Case project that were approved in Case No. U-20836 but subsequently disallowed in Case No. U-21297, consisting of $5.7 million in 2021 and $5.7 million in 2022-2023.
- Provide details supporting the capital that is being sought for the Company's Error Free Communication – Outage Status initiative shown in Exhibit A-12, Schedule B5.4 Distribution Plant – Technology and Automation page 18, Lines 33 and 40 for 2022-2023 investments and Line 33 for 2024-2025 investments, in the amount of $8.4 million for the historical test year ended December 31, 2022, $5.2 million in the 2023-2024 bridge period (for the 24 months ending December 31, 2024), and $0.6 million for the projected 2025 test year period ending December 31, 2025.
- Discuss the variance of actual 2022 capital spend compared to 2022 capital spend approved in Case No. U-21297. Additionally, provide explanation for projected budget differences in 2023 and 2024 (as compared to U-21297) for projects that meet the requirement established in the U-20162 final order.
- Provide details of the Company's actual $112.4 million Customer Service Operation and Maintenance (O&M) expenses for the twelve-month period that ended December 31, 2022, and support the Company's projected $118.6

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million Customer Service O&M expenses for the projected test year period ending December 31, 2025.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.7.3	IT Customer Service Capital Expenditures
A-13	C5.7	Projected Operation and Maintenance Expenses – Customer Service
A-13	C5.9.2	ACPP and TOD Regulatory Asset Deferrals
A-24	N1.1	Customer Service IT Business Cases - Executive Summaries
A-24	N2	Historical Spend Variance Summary
A-24	N3.1	Customer IT Capital Investments with Additional Project Details
A-24	N5	Call Volume Reduction Savings Summary
A-24	N6	NPV Model for Digital Self-Service Projects
A-24	N7	Error Free Communication (EFC) Capital Spend
A-24	N8	IT Capital Approved in Case No. U-20836
A-24	N9	Operational Efficiencies Summary
A-24	N10	2022-2024 Outage and EFC Channel Enhancements

Q9. Were these exhibits prepared by you or under your direction?

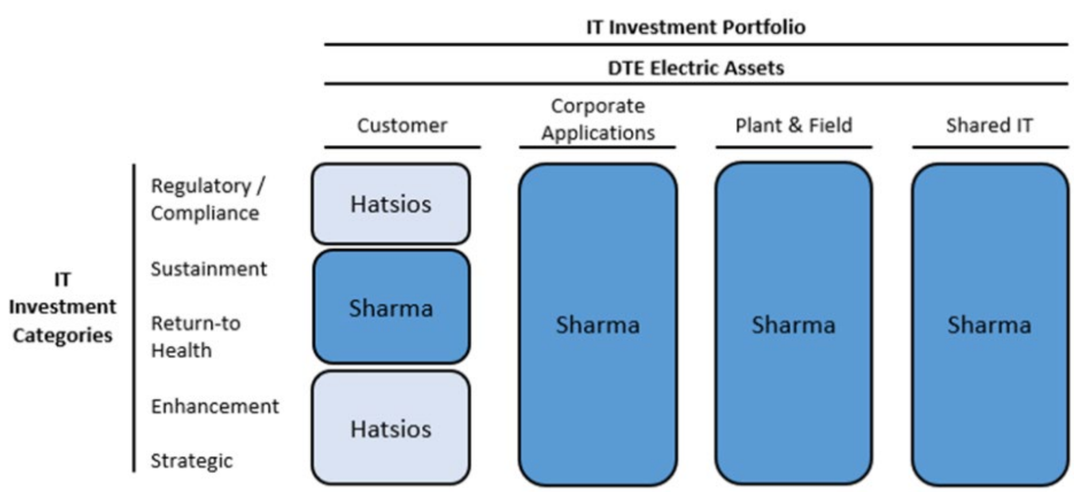
A9. Yes, they were. I co-sponsor Exhibit A-24, Schedule N2, with Company Witness Sharma and Exhibit A-13, Schedule C5.9.2 with Company Witness Bennett.

Part 2. Customer Service IT Portfolio Overview

Q10. How do the projects in the Customer Service IT Portfolio align with the Company's overall IT Investment Portfolio?

A10. The Customer IT Portfolio is a subset of DTE's IT Investment Portfolio and has been developed in parallel with the DTE IT 5-year plan (2021-2025) filed in Case No. U-20561. A view of the structure of the DTE IT Investment Portfolio, the associated IT Investment Categories, and the responsible witness in the instant case is provided in Figure 1.

Figure 1 - DTE IT Investment Portfolios



Consistent with the other IT Investment Portfolios, the projects in the Customer Service IT Portfolio have been categorized into five areas of targeted investment –

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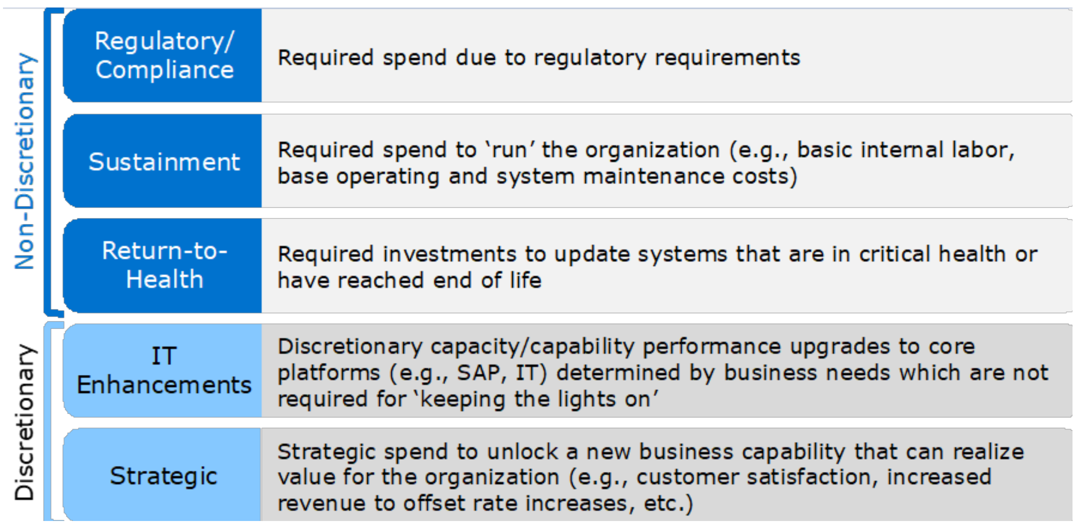
Regulatory/Compliance, Sustainment, Return to Health, IT Enhancements, and Strategic (Figure 2).

Figure 2 - DTE IT Investment Categories



Q11. Which IT Investment Categories within the Company's Customer Service IT Portfolio are addressed in your testimony?

A11. As shown in Figure 1, my testimony includes projects within DTE Electric's Customer Service IT Portfolio in the following IT Investment Categories: Regulatory and Compliance, IT Enhancements, and Strategic. As noted in Figure 2, the capital projects addressed in my testimony relate directly to those non-discretionary and discretionary projects that either are required by mandate or compliance rules (Regulatory and Compliance), or directly target enhancing the customer experience, reducing operational costs, and improving the effectiveness with which we serve customers (IT Enhancements and Strategic).

Not included in my testimony are those Customer Service IT Portfolio projects that are included in the Sustainment and Return-to-Health IT Investment Categories. These are included in Exhibit A-12, Schedule B5.7.2 and discussed in Company Witness Sharma's testimony.

Part 3. Company Witness Hatsios Sponsored Projects – Overview

Q12. Please confirm DTE Electric's Customer Service capital investments in each of the three IT Investment Categories (e.g., Regulatory/Compliance, IT Enhancements, Strategic).

A12. As reflected in Exhibit A-12 Schedule B5.7.3, DTE Electric will invest the below amounts in the three IT Investment Categories covered in my testimony:

- Regulatory and Compliance – the Company will invest $59.9 million in the Regulatory and Compliance category over the course of 48-months ending December 31, 2025, consisting of $21.1 million in the historical period, $21.3 million in the 2023-2024 bridge period, and $17.5 million in the 2025 test period, as shown in Lines 1 through 17 of the Capital Expenditures Exhibit A-12 Schedule B5.7.3.
- IT Enhancements – the Company will invest $18.8 million in the IT Enhancements category over the course of 48-months ending December 31, 2025, consisting of $7.4 million in the historical period, $4.2 million in the 2023-2024 bridge period, and $7.2 million in the 2025 test period, as shown in Lines 18 through 26 of the Capital Expenditures Exhibit A-12 Schedule B5.7.3.
- Strategic – the Company will invest $90.6 million in the Strategic category over the course of 48-months ending December 31, 2025, consisting of $33.2 million

in the historical period, $49.0 million in the 2023-2024 bridge period, and $8.4 million in the 2025 test period, as shown in Lines 27 through 47 of the Capital Expenditures Exhibit A-12 Schedule B5.7.3.

Q13. How do the Customer Service Regulatory and Compliance, IT Enhancements, and Strategic capital projects in your testimony align with the Company's priorities?

A13. The Company is committed to providing reliable, safe, and affordable utility service to its customers, expanding its renewable energy portfolio, and reducing its carbon footprint. DTE's Customer Service organization is aligned with and supports these priorities, and is committed to cost effectively providing customers with engaging and satisfying transactional (e.g., orders) and non-transactional (e.g., inquiries) interactions across its service channels, which includes enrolling customers in the Company's voluntary clean energy products and services.

To that end, the Regulatory, IT Enhancement, and Strategic capital projects supported in my testimony are intended to deliver the following outcomes and customer benefits:

1. Effective and Affordable Digital Self-Service Solutions – Provide customers with satisfying and seamless digital self-service alternatives to having to call the Contact Center, which makes it easier for customers to complete their interactions, improve service levels, and reduce operating expenses, with resultant savings passed on to customers through the ratemaking process.

2. Increased Operational Efficiencies – Create efficiencies across the Customer Service operating groups to improve the efficiency and productivity of our operations and projects, or to reduce the cost of operations, with resultant savings passed on to customers through the ratemaking process.
3. Enhanced Customer Interactions – Improve the effectiveness and quality with which the Company interacts and communicates with customers, ensuring customers receive timely, accurate, and consistent information.
4. Enhanced and Expanded Clean Energy Products – Provide customers with voluntary programs and services that promote and support their carbon reduction goals and the growth of the Company's renewable energy assets.

Q14. Please specify how capital projects are consolidated and presented in your testimony to align with the above-referenced outcomes and customer benefits.

A14. I have consolidated the projects for which I am providing testimony in a manner that aligns the individual projects with the outcomes and customer benefits described in my response to Q13. As such, the remainder of the capital IT portion of my testimony is organized as shown below.

Part 4 – Digital Self-Service Projects
Part 5 – Operational Efficiency Projects
Part 6 – Projects that Enhance Customer Interactions
Part 7 – Regulatory, Compliance, and Clean Energy Projects
Part 8 – 2022 Historical Capital Project Variance

Q15. Are there any IT projects shown in Exhibit A-12 Schedule B5.7.3 that have already been approved for cost recovery in a prior rate case and for which the Company is not providing additional supporting testimony in the instant case?

A15. Yes. The projects in Table 1 below, which were supported in my testimony in Case No. U-21297, and which were approved for cost recovery by the Commission in their final order in that case, will not be further discussed in my testimony in the instant case.

Table 1. Capital Projects Approved in U-21297

Project Name	Portfolio	Category	U-21534 Exhibit Reference	U-21297 Exhibit Reference
ACPP/Time of Day	Customer	Regulatory/Compliance	Line 1, A-12 B5.7.3	Line 1, A-12 B5.7.3
Corporate Energy Forecasting	Customer	Regulatory/Compliance	Line 2, A-12 B5.7.3	Line 2, A-12 B5.7.3
MIGP - Fixed Price Product(Rider 17)	Customer	Regulatory/Compliance	Line 5, A-12 B5.7.3	Line 3, A-12 B5.7.3
MIGP Section 61 Settlement	Customer	Regulatory/Compliance	Line 9, A-12 B5.7.3	Line 6, A-12 B5.7.3
Payment Stability Plan	Customer	Regulatory/Compliance	Line 13, A-12 B5.7.3	Line 8, A-12 B5.7.3
Treasury Credential on File	Customer	Regulatory/Compliance	Line 17, A-12 B5.7.3	Line 13, A-12 B5.7.3
Customer Legacy Applications Enhancement	Customer	IT Enhancements	Line 20, A-12 B5.7.3	Line 15, A-12 B5.7.3
Customer Service Communications	Customer	Strategic	Line 32, A-12 B5.7.3	Line 33, A-12 B5.7.3
Enhanced Training Environments	Customer	Strategic	Line 34, A-12 B5.7.3	Line 35, A-12 B5.7.3
Field Service Management Billing & Metering	Customer	Strategic	Line 37, A-12 B5.7.3	Line 40, A-12 B5.7.3
Field Service Management for RM&P	Customer	Strategic	Line 36, A-12 B5.7.3	Line 39, A-12 B5.7.3
Platform Integration Component	Customer	Strategic	Line 43, A-12 B5.7.3	Line 50, A-12 B5.7.3
Qualtrics Expansion	Customer	Strategic	Line 44, A-12 B5.7.3	Line 53, A-12 B5.7.3
Speech Analytics	Customer	Strategic	Line 46, A-12 B5.7.3	Line 57, A-12 B5.7.3
Workforce Automation for Contact Center	Customer	Strategic	Line 47, A-12 B5.7.3	Line 58, A-12 B5.7.3

Q16. Are you providing any additional project details for the projects in Exhibit A-12, Schedule B5.7.3?

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A16. Yes. I am providing in Exhibit A-24, Schedule N1.1 business case executive summaries for all the projects, and project capital, included in Exhibit A-12, Schedule B5.7.3. Exhibit A-24 Schedule N3.1 also provides a greater level of detail in the format requested by Commission Staff, as set forth in new filing requirements adopted in the Commission's May 18, 2023 Order in Case No. U-18238.

Part 4. Digital Self-Service Projects

Q17. Can you explain why the Company is investing capital in its Digital Self-Service solutions?

A17. Yes. The Company is investing capital in its digital self-service solutions to provide customers with seamless and satisfying self-service alternatives to having to call the Contact Center, both to meet the demands of those customers who prefer to engage with the Company in a self-service channel, and to reduce the volume of live calls handled by DTE's CRs.

Q18. What is the Company's motivation to reduce the volume of calls handled by CRs in its Contact Center?

A18. The cost of Contact Center operations represents the largest portion of the total Customer Service (CS) Operating & Maintenance (O&M) expense, as shown in Figure 3, which reflects the percent of the total CS O&M expense incurred by each of the CS operating groups during the 2022 historical period – as provided in Exhibit A-13, Schedule C5.7, Line 5, Column G.

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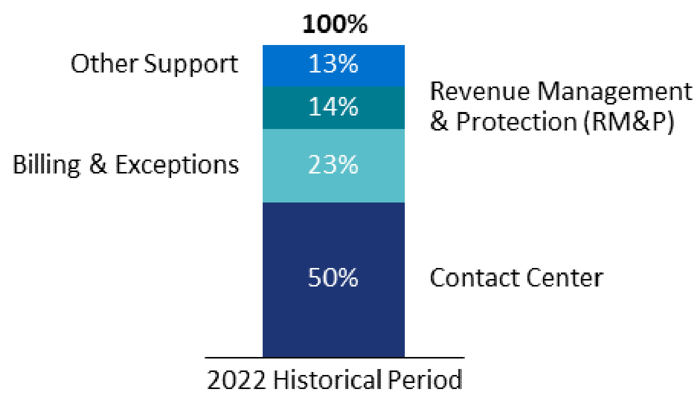
Figure 3 - CS O&M Expense (% of spend by group)



In the 2022 historical period, the Contact Center contributed 50% of the total CS O&M expense, with the most significant driver of Contact Center costs being the handling of live phone calls by CRs. In fact, each incremental call handled by a CR in the Contact Center costs the Company $11.34, which reflects the 2022 weighted average cost of the Company's internal and external CR resources, and includes overhead costs (e.g., benefits, payroll taxes, etc.) for the internal DTE CRs.

Q19. How do customers benefit from the reduction in call volumes?

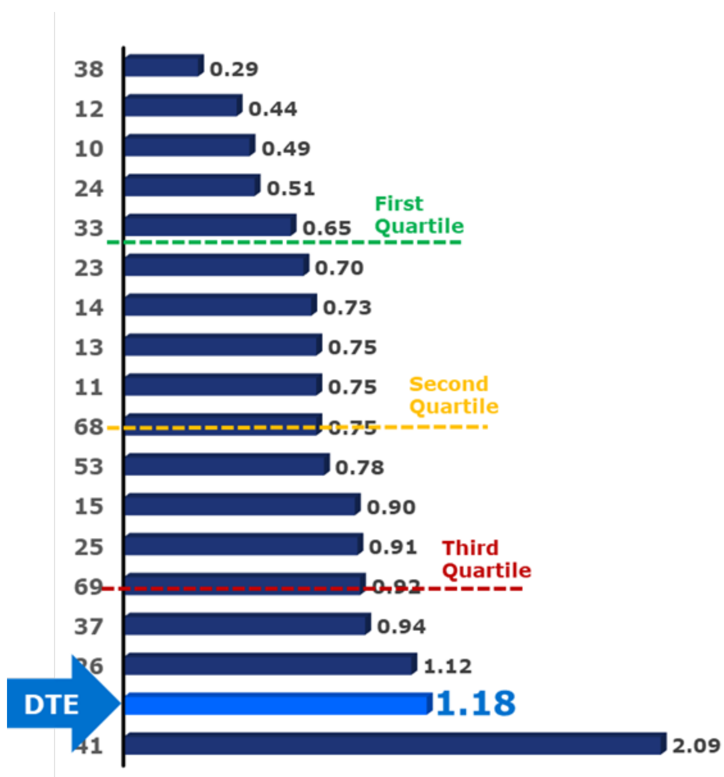
A19. CRs continue to handle millions of live calls from customers every year, which at $11.34/call results in tens of millions of dollars in DTE Contact Center O&M expense, which is passed on to customers through the utility ratemaking process. As such, reducing calls represents a significant opportunity for the Company to reduce its operating costs and the associated O&M expense that is passed on to customers.

Additionally, with fewer live calls to handle, the Company can sustain its desired service levels (e.g., average speed of answer, call abandon rates), and CRs will have the capacity to more effectively handle those more complex inquiries from customers that may not be as effectively handled in a digital self-service solution (e.g., low-income self-sufficiency program – LSP and payment stability plan – PSP enrollments).

Q20. How does the Company's volume of calls compare to its peers?

A20. The Company continues to lag its utility peers in the volume of calls it handles per customer, as reflected in the most recent 2023 First Quartile Consulting Benchmarking Study (Figure 4).

Figure 4 - 2023 First Quartile Live Calls per Customers



The above study reflects full-year 2022 data as submitted by each of the participating utilities, with DTE currently at the bottom of the 4th quartile, indicating that there remains significant opportunity for DTE to reduce calls, and the associated costs of handling those calls.

Q21. What are the most common reasons why customers call the Company?

A21. The Company has identified the types of transactional (e.g., orders) and non-transactional (e.g., inquiries) interactions with customers that drive the majority of its total call volume, which I have summarized below.

1. Collection – Calls from customers who received a shutoff notice, or have been disconnected for nonpayment, and are contacting the Company to discuss the options available to them to avoid shutoff or to restore service. Many of these calls are from the Company's most vulnerable, low-income customers who are calling about available energy assistance and to discuss payment plan options.
2. Billing – Calls from customers who want to verify their account balance, have questions about their bill, or want to enroll in one of the Company's billing programs (e.g., Budget Wise Billing, ebill).
3. Move-In/Move-Out (MIMO) – Calls from existing and new customers requesting to Start Service at a new location, Stop Service at an existing location, Transfer Service between locations, or inquiry about or change to an existing MIMO service order.
4. Payments – Calls from customers who want to pay their monthly bill or to check on the status of a recent payment.

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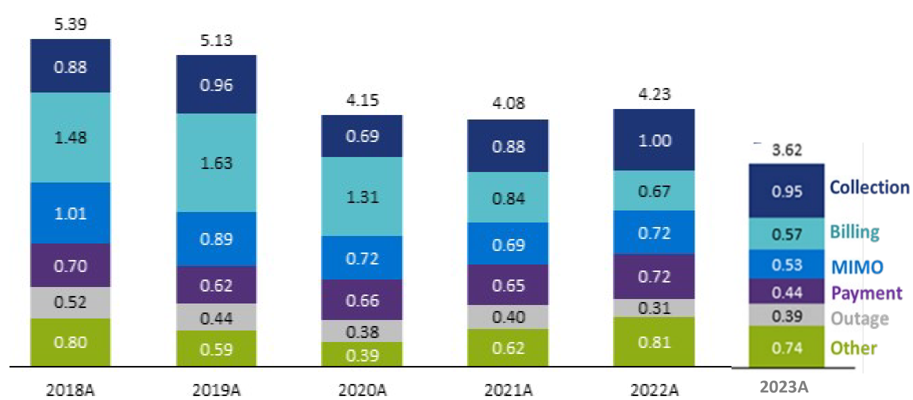
5. Outage – Calls from customers who are reporting an electric outage or checking on the status of a reported electric outage.

Q22. How has the total volume of calls been trending in the past five years?

A22. The Company has seen a reduction of 1.77 million calls from 2018-2023, with approximately one-third of that reduction coming in 2023 (Figure 5).

Figure 5 - Call Volumes by Type (millions)



The call volumes reflected in Figure 5 include the total volume of calls received from both DTE Electric and DTE Gas customers. For the remainder of my testimony, unless otherwise stated, the outcomes and customer benefits associated with each of the capital projects for which I am providing testimony, can be assumed to be shared between DTE Electric and DTE Gas customers.

Q23. How have the Company's historical investments in its digital self-service solutions contributed to the reduction in calls since 2018?

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A23. The Company has been able to enhance and expand its digital self-service solutions in a manner that provides customers with increased and effective self-service alternatives to calling the Contact Center. Over time, as these digital solutions grew and matured, customers increasingly chose to engage in the use of these solutions in lieu of calling the Contact Center.

For example, in 2018, customers could view and pay their bill online, report and check on the status of outages on the Web and in the Mobile App, and use the Web to complete their MIMO transaction. Today, customers can do all those things and more, including, but not limited to, interacting with the Company via social media and Web chat, processing Collection restores on the Web and in the Interactive Voice Response (IVR) system, enrolling in a payment extension in the IVR through a Virtual Assistant (VA) and on the Web, self-analyzing their bills online and in the IVR through a VA, processing MIMO requests in the IVR through a VA, and tracking the status of their MIMO and Collection requests using the Company's online order trackers.

Q24. How does the Company measure the level of customer engagement in the use of its digital self-service solutions?

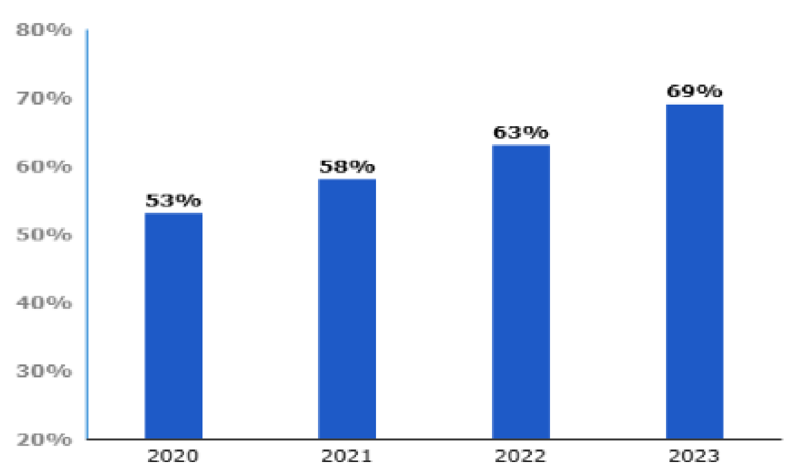
A24. The Company has established a "Digital Engagement Rate" (DER) metric for each of the five categories of customer interactions – Collection, MIMO, Billing, Payment, and Outage – to measure and track the engagement of its customers in the digital self-service solutions.

For each of the identified five customer interactions, the Company measures the percent of customers who complete a transactional interaction in a digital self-service channel, relative to the total number of completed served and self-served transactional interactions – e.g., if customers complete a total of 20,000 total MIMO transactions in a week, and 10,000 of those are successfully completed using a digital self-service solution, the MIMO DER for that week would be 50%. With the exception of Billing interactions, for which non-transactional inquiries are included in the DER, non-transactional interactions are excluded from the DER calculation for the other customer interactions. Going forward, I will use the term transaction when discussing the DER for each category of customer interactions.

Q25. How has the DER been trending in recent years?

A25. The Company has been tracking the DER for each transaction since 2020, and has seen the overall DER steadily increase from 53% to 69% (Figure 6).

Figure 6 - Digital Engagement Rate (2020-2023)



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Q26. What factors impact the DER, and how has the DER increased for each of the transactions?

A26. The DER for each transaction is a function of the number of customers who choose to use a digital self-service solution, and the number of those customers who are able to successfully complete their interaction in that solution, which the Company refers to as the "Digital Completion Rate" (DCR).

In other words, to increase the DER for a particular transaction, the digital self-service solutions for that transaction must be seen by customers as an attractive alternative to calling the Contact Center, and it must be designed so that a high percentage of customers who choose to use a digital solution are able to successfully complete their transaction. In general, the more complex the transaction, and the more information customers are asked to provide, the more opportunity there is for customers to "drop-off" and call the Contact Center to complete their transaction. Below is a summary of the DER (Table 2) for each transaction since 2020, along with the Company's long-term targets.

Table 2. Digital Engagement Rate by Transaction

Transaction	2020	2021	2022	2023	Long Term Target
Collection	0%	5%	16%	30%	60%
MIMO	19%	25%	32%	42%	60%
Billing	76%	86%	89%	92%	95%
Outage	91%	93%	94%	96%	98%
Payment	78%	80%	82%	84%	85%
Overall	**53%**	**58%**	**63%**	**69%**	**80%**

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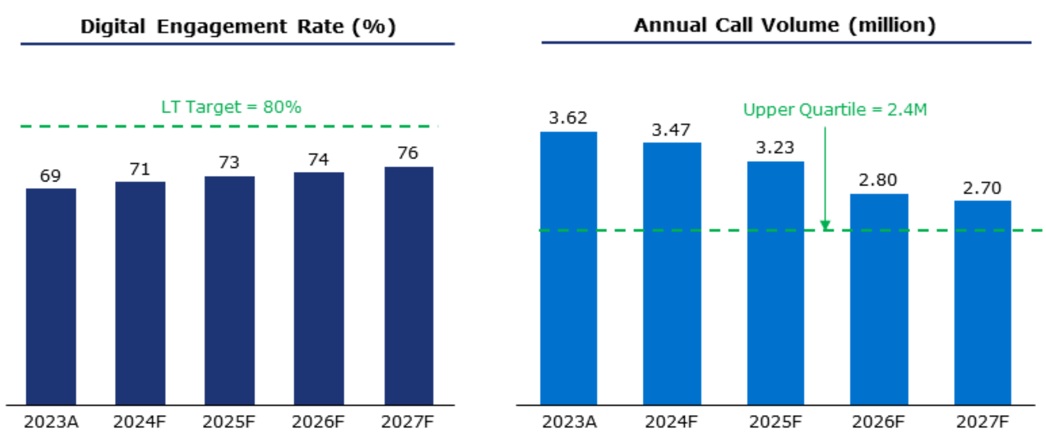
These increased DERs are a direct result of the Company's investment in the expansion of its digital self-service offerings, and its commitment to ensure that customers who choose to engage in the use of these solutions are able to successfully complete their transaction.

Q27. What are DER and call volumes that the Company is forecasting to achieve through its capital investments in its digital self-service solutions?

A27. The Company is forecasting that its investments in its digital solutions will further increase customer engagement in the digital solutions, increase DER closer to the Company's long-term target, and reduce call volumes to near upper quartile levels (Figure 7).

Figure 7 - Forecasted DER and Call Volumes



Detailed summaries of the realized and forecasted DER increases, call volume reductions, and O&M savings can be found in Exhibit A-24, Schedule N5.

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Q28. What are the total cumulative call volume savings the Company is forecasting to achieve through its investments in the digital self-service solutions?

A28. As seen in Exhibit A-24, Schedule N5, Page 1, Column h, Line 16, the Company is forecasting that reducing total call volume to 2.7 million (Figure 7) will provide customers with total cumulative net O&M savings through 2027 of $15.6 million.

Q29. Is the Company removing the forecasted call volume savings from its operating budget and its requested O&M recovery in the instant case?

A29. Yes. As it did in U-21297, the Company is removing the annual call volume savings for the projected test year from the Customer Service O&M budgets and from its requested O&M recovery in the instant case, which is discussed in my Customer Service O&M testimony (Part 9) and as reflected in my supporting Exhibit A-13 Schedule C5.7 on Line 5, Column (k) for Customer Records and Collection Expenses, and in footnote 3. This reduction is also highlighted in Exhibit A-24, Schedule N5, Page 1, Column f, Line 17.

Q30. Which projects support the enhancement and expansion of the Collection digital solutions?

A30. The Company will invest $10.7 million in five projects to enhance and expand the Collection digital solutions over the course of 48-months ending December 31, 2025, consisting of $2.8 million in the historical period, $5.9 million in the 2023-2024 bridge period, and $2.0 million in the 2025 test period, as shown in Exhibit A-12, Schedule B5.7.3, and which I have summarized in Table 3 below. See Exhibit A-24 Schedule N3.1 Lines 13-15, 20-21, 25-26, 41 for additional project details.

Note that $0.4 million of the total $2.8 million in 2022 historical spend for the Customer Relationship and Billing (CR&B) Enhancement project was allocated to the digital projects, with $0.1 million allocated to Collection. $2.3 million of the $6.8 million in 2022 historical capital for the Journey Work Product Transformation Teams project was also allocated to Collection digital solutions.

Table 3. Collection Digital Self-Service Capital ($000s)

Line Item	Project Name	Year	Total Capital	Allocated to Collections
21	CR&B Enhancement	2022	$2,794	$100
29	Collection Web Self-Service	2023-25	$7,880	$7,880
31	Customer Closed Loop Development	2022	$314	$314
39	Journey Work Product Transformation Teams	2022	$6,744	$2,300
48	API Integration Security Gateway – API Layer*	2022	$70	$70
		Total (2022-2025)	**$17,802**	**$10,664**

* Included in Projects < $250K

Q31. Can you elaborate on the scope of work that is being funded by the Collection digital self-service capital?

A31. Yes. The capital allocated to the Collection digital self-service solutions is intended to enhance the Company's existing Collection digital solutions, and to expand the number of available digital solutions, as follows – please note in 2022-2023 the four projects in Table 3 incurred $5.1 million in capital to modify the customer systems as necessary to deliver the highlighted improvements, while in 2024-2025 an additional $5.5 million in capital will be spent solely by the Collection Web Self-Service project.

2022-2023 Collection Digital Improvements

- Increase Collection DCR and DER by addressing defects and cumbersome process flows in the digital solutions that are preventing customers from successfully completing their digital transaction (2022-2023).
- Provide customers the ability to process a restore of service on the Web (February 2023).
- Provide customers the ability to enroll in a payment extension hold on the Web (August 2023).
- Provide customers the ability to check on the status of an account lock on the Web for the status of payment extension holds, medical holds, pending energy assistance funding, and pending income status verifications (October 2023).

2024-2025 Collection Digital Improvements

- Increasing Collection DCR and DER by addressing defects and cumbersome process flows in the digital solutions that are preventing customers from successfully completing their digital transaction (2024-2025).
- Expanding restore and payment extension eligibility to include more customers (2024-2025).
- Providing the ability for customers to enroll in a payment arrangement on Web to pay their past due amount over time. (May/June 2024).
- Providing customers with new online assistance tools that will guide customers who are having difficulty paying their bill to the most appropriate payment solutions, and sources of energy assistance (2024-2025).

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Q32. What are the realized and forecasted customer benefits of the identified scope of work funded by the Collection digital self-service capital?

A32. In terms of call volume reductions, while 2023 Collection call volumes are not materially different than they were four or five years ago, they have been reduced by 50,000 relative to 2022 (Figure 5). This is despite an 11% increase in the number of active low-income customers versus 2022, a 28% increase in the number of low-income customers who reached final arrears status, a 15% reduction in available Energy Assistance (EA) funding, and an increase in shutoff notices from 1.9 million to 2.1 million.

Together, these factors would be expected to significantly increase the volume of Collection calls, especially for general inquiries and inquiries related to EA funding. The Company maintains that the expected increase in Collection inquiry calls, was mitigated by a reduction in the number of calls from customers who chose to use a digital solution to restore service, to enroll in a payment agreement, or to check on the status of an account hold.

Given the results achieved to-date from the Collection digital self-service capital investments, the Company is forecasting that its historical and planned investments in the Collection digital self-service solutions will increase the Collection DER to 48% by 2027, will enable a cumulative decrease of 343,600 calls (2023-2027), and will provide customers with a cumulative $3.9 million in O&M savings (2023-2027). The annual Collection call volumes and associated O&M savings are provided in Exhibit A-24, Schedule N5.

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Q33. Are there any other benefits, beyond O&M savings, to customers of the Company's investments in Collection digital self-service?

A33. Yes. While the Company anticipated that its payment extension VA and Web solutions would provide increased numbers of customers an easy-to-use tool that allows them more time to pay their past due balance, it did not expect such rapid customer adoption of these solutions, nor did it expect the number of payment enrollments to triple, as shown in Table 4.

Table 4. Payment Extension Summary

Year	Total Payment Extensions	DER	Paid On-Time
2021	47,400	4%	37%
2022	88,650	40%	39%
2023	144,350	67%	44%

The data in Table 4 indicates that in 2023, 67% of all payment extension enrollments were completed in a self-service solution, and 44% of the total enrollments were successfully paid within the required 10-day post enrollment period. In other words, 63,500 times (144,350 enrollments times 44% paid on-time), customers were able to leverage the use of a payment extension to pay their past due balance in full and avoid a shutoff of service.

Q34. Which projects support the expansion of the MIMO digital transaction?

A34. The Company will invest $15.8 million in four projects to enhance and expand the MIMO digital self-service solutions over the course of 48-months ending

December 31, 2025, consisting of $4.4 million in 2022 historical period, $8.9 million in 2023-2024 bridge period, and $2.5 million in 2025 test period capital, as shown in Exhibit A-12 Schedule B5.7.3, which I have summarized in Table 5 below. See Exhibit A-24 Schedule N3.1 Lines 25-26, 39-40, 41, 58-60 for additional project details.

Note that $0.4 million of the total $2.8 million in 2022 historical spend for the Customer Relationship and Billing (CR&B) Enhancement project was allocated to the digital projects, with $0.2 million allocated to MIMO. $3.0 million of the $6.8 million in 2022 historical capital for the Journey Work Product Transformation Teams project was also allocated to MIMO digital solutions.

Table 5. MIMO Digital Self-Service Capital ($000s)

Line Item	Project Name	Year	Total Capital	Allocated to MIMO
21	CR&B Enhancement	2022	$2,794	$200
38	IVR Virtual Assistants	2022	$1,161*	$1,161
39	Journey Work Product Transformation Teams	2022	$6,744	$3,000
41	MIMO Web Self-Service	2023-2025	$11,415	$11,415
		Total (2022-25)	**$22,114**	**$15,776**

*Net of 2023 reduction of ($109,000), as shown in Exhibit A-12, Schedule B5.7.3

Q35. Can you elaborate on the scope of work that is being funded by the MIMO digital self-service capital?

A35. Yes. The focus for the MIMO digital self-service solutions in 2022-2023 was to enhance the existing MIMO Web, and MIMO start service Virtual Assistant (VA), solutions to address defects and cumbersome process flows that were preventing customers from completing their transaction (2022-2023), to enhance and expand the MIMO VA solutions to include start and transfer service request (2022), and to migrate MIMO Web from an on-premise solution to the cloud (2022-2023).

Below is an overview of the types of MIMO digital self-service improvements that were implemented from 2022-2023 through the Company's capital investments – please note in 2022-2023 the four projects in Table 5 provided $9.8 million in capital to modify the customer systems as necessary to deliver the highlighted improvements, while in 2024-2025 an additional $6.0 million in capital is being provided solely by the MIMO Web Self-Service project.

<u>2022 MIMO Digital Improvements</u>

- Implemented MIMO start and transfer service VA solutions.
- MIMO Web start-service migrated to a cloud-based platform, and in parallel improved the stop MIMO user experience and interfaces (UX/UI).
- Allowed MIMO Web customers to enter only the last four digits of their social security number to validate their identity.
- Removed and/or replaced confusing Web error messages.
- Removed redundant and confusing Web tiles.
- Created ability to validate international addresses – from customers moving to DTE's service territory from outside the United States.

<u>2023 MIMO Digital Improvements</u>

- MIMO Web stop and transfer service migrated to a cloud-based platform, and in parallel improved the overall MIMO stop and transfer service user experience and user interface.
- Allowed authenticated Web customers to bypass identification requirements, which was a common point of failure for existing DTE MIMO customers.
- Continued to improve the address search and validation MIMO Web functionality, which was a significant point of failure for customers.
- Made it easier for customers who want to change the scheduled date of their MIMO order by directing customers, via notifications and the MIMO online order tracker, to the change order function in MIMO Web, and ensuring the solution is easily navigated so they can complete their request.
- Incorporated Web chat across the MIMO Web transactions to provide assistance to customers who get "stuck" in the process.

The focus for the Company's 2024-2025 capital investments, will be to continue to enhance the MIMO Web and VA solutions, with the goal of expanding the number of MIMO scenarios that can be handled in a digital solution, and eliminating defects and cumbersome process flows that are preventing customers from completing their digital transaction.

2024-2025 MIMO Digital Improvements

- Additionally-enhanced user experience and user interface experience.
- Waiving identification requirements for customers who authenticate by logging into the Web to process their MIMO request.

- Creating a Web stop service guest option, so customers do not have to login to complete their stop service request.
- Eliminating Web technical errors, looping, blank page with error, and ad blockers.
- Adding a Web chat link to all MIMO customer notifications.
- Expanding the Web and VA error logs to include secondary codes for improved root cause identification.
- Fixing the defect related to document reversals, which are failing during a digital move and requiring CR escalations.
- Implementing new VA skills to handle MIMO order changes, cancels and inquiries.

Q36. What are the realized and forecasted customer benefits of the identified scope of work funded by the MIMO digital self-service capital?

A36. Enhanced and more effective MIMO Web start, stop, and transfer digital solutions, along with the implementation of the MIMO VA solutions, provided customers with more, and more effective, digital self-service solutions in which they could choose to engage to complete their MIMO request. As a result, the MIMO DER increased from 19% in 2020, to 42% in 2023 (Table 2), which has driven the number of MIMO calls to an all-time low of 530,000 in 2023 (Figure 5).

Given the results achieved to-date, the Company is forecasting that its historical and planned investments in the MIMO digital self-service solutions will increase the MIMO DER to 56% by 2027, will enable a cumulative decrease of 338,000 calls (2023-2027), and will provide customers with a cumulative $3.8 million in

O&M savings (2023-2027). The annual MIMO call volumes and associated O&M savings are provided in Exhibit A-24, Schedule N5.

Q37. Which projects support the expansion of the Outage digital transaction?

A37. The Company invested $7.8 million in 2022 historical period spend in two projects to enhance and expand the Outage digital self-service solutions over the course of 12-months ending December 31, 2022, which are included in Exhibit A-12 Schedule B5.7.3, and which I have summarized in Table 6 below. $6.3 million of the $14.9 million in 2022 historical capital for the Error Free Communications – Outage Status project was allocated to Outage digital transaction. $1.4 million of the $6.8 million in 2022 historical capital for the Journey Work Product Transformation Teams project was also allocated to Outage digital transaction. See Exhibit A-24 Schedule N3.1 Lines 30-32, 41 for additional project details.

Table 6. Outage Digital Self-Service Capital ($000s)

Line Item	Project Name	Year	Total Capital	Allocated to Outage
35	Error Free Communication – Outage Status	2022	$14,904	$6,330
39	Journey Work Product Transformation Teams	2022	$6,744	$1,444
		Total (2022)	**$21,648**	**$7,774**

Q38. Can you elaborate on the scope of work that is being funded by the Outage digital self-service capital?

A38. Yes. Customers are very engaged in the use of the Outage digital self-service solutions, as evidenced by the 96% Outage DER in 2023 (Table 2). However, the record storm activity and resulting number of customer outages in 2021 and 2023, have provided greater insight into the opportunities to enhance the Outage self-service experience, and the quality of information the Company provides customers during an outage.

The $7.8 million in capital allocated to the Outage transaction reflects the entirety of the Company's 2022 capital investments in its Outage digital self-service solutions, and was used to improve the usability, ease-of-navigation, and quality of the messaging and notifications provided to customers who were reporting or checking on the status of storm related outages using the Web. I have summarized these improvements below.

<u>2022 Outage Web Improvements</u>

- Ongoing enhancements to the newly launched (late 2021) Police/Fire, Municipality, and Outdoor Lighting cloud site.
- Integrated Outage Web with the new "Where is My Order" (WISMO) and Premise Power Status (PPS) Outage systems.
- Ongoing enhancements to the user experience and user interface and navigation of the Web and Mobile Web Outage centers.
- Enhanced and more accurate customer-facing error messages.
- Integrated Web Outage with the new cognitive address search to make it easier for customers to search and find address.
- Completed changes required to support the planned 2023 Advanced Distribution Management System (ADMS) launch.

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Q39. What are the realized and forecasted customer benefits of the identified scope of work funded by the Outage digital self-service capital?

A39. The 2022 Outage Web self-service enhancements improved the visibility of the Outage Web content, improved the quality of the information presented to customers regarding their outage, and made navigation of the Outage Website easier for customers, which resulted in increased numbers of customer reporting an Outage to successfully complete their transaction in a digital channel – 87% in 2022 versus 92% in 2023 – and a corresponding increase in the Outage DER, which went from 94% in 2022, to 96% in 2023 (Table 2).

The volume of mitigated calls from this increased DER is dependent on storm activity, and the number of customers who are reporting an Outage, which increased from 900,000 in 2022, to 2.9 million in 2023. As a result, Outage reported by a CR increased from about 52,000 in 2022, to just over 125,000 in 2023, more than doubling. However, Outage reporting through the digital self-service solutions more than tripled from just over 850,000 in 2022 to 2.8 million in 2023, indicating that significant numbers of customers chose to engage in the use of an Outage digital solution rather than call to report their Outage, with 92% successfully able to complete their transaction as compared to 87% in 2022.

Had the percent of successfully completed Outage digital transactions not increased from 87% to 92%, as a result of the Company's 2022 capital investments, Outage reporting calls to the Contact Center could have increased by over 157,000. This assumes that 3.15 million Outage reports were attempted in a digital solution (2.9 million completed transactions / 92% completion rate), and that if the completion

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rate in 2023 had remained at 87%, there would have been an additional over 157,000 failed digital Outage reports (3.15 million attempted in a digital solution x 5% decrease in percent completed), which could have resulted in a call to the Contact Center.

Regarding the Company's 2023-2024 investments, the focus for the Outage transaction in 2023-2024 is on the improvement of the timeliness and accuracy with which we provide customer power status updates, restoration estimates, and other outage information and notifications. These investments are part of the Company's Error Free Communication (EFC) – Outage Status initiative, from which $6.3 million (Table 6) was used to fund the described 2022 Outage Web improvements, of which $3.8 million was previously approved in the Commission's final order in Case No. U-20836, as reflected in Exhibit A-24, Schedule N8, Page 2, Line 23. Any required enhancements to the Outage digital self-service solutions from 2023-2024 are in support of the EFC- Outage Status initiative, which I will discuss in detail in Part 6 of my testimony related to "Projects that Enhance Customer Interactions".

Cumulatively, the Company is forecasting its investments in the Outage digital solutions to increase the Outage DCR to 95% by 2027, will enable a cumulative decrease of 32,500 calls (2023-2027), and will provide customers with a net cumulative $0.4 million in O&M savings (2023-2027). The annual Outage call volumes and associated O&M savings are included in Exhibit A-24, Schedule N5.

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Q40. Which projects support the enhancement and expansion of the Billing digital solutions?

A40. The Company will invest $5.0 million in three projects to enhance and expand the Billing digital self-service solutions over the course of 36-months ending December 31, 2024, consisting of $3.5 million in 2022 historical period and $1.5 million in 2023-2024 bridge period capital, as shown in Exhibit A-12 Schedule B5.7.3, which I have summarized in Table 7 below. Note that $0.4 million of the total $2.8 million in 2022 historical spend for the Customer Relationship and Billing (CR&B) Enhancement project was allocated to the digital projects, with $0.1 million allocated to Billing. See Exhibit A-24 Schedule N3.1 Lines 10-12, 25-26 for additional project details.

Table 7. Billing Digital Self-Service Capital ($000s)

Line Item	Project Name	Year	Total Capital	Allocated to Billing
21	CR&B Enhancement	2022	$2,794	$100
27	Bill Management	2022	$3,425	$3,425
28	Billing Web Self-Service	2023-24	$1,480	$1,480
		Total (2022-24)	**$7,699**	**$5,005**

Q41. Can you elaborate on the scope of work that is being funded by the Billing digital self-service capital?

A41. Yes. The three projects in Table 7 are providing $5.0 million in capital from 2022-2024 to enhance the existing Billing digital solutions, which includes enhancing the digital user experience by improving the quality of the data presented on the Web, addressing defects in the online bill management tool, and enhancing the bill management tool to support the Time-of-Day (TOD) rate implementation.

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Q42. Can you describe the scope of $3.4 million in capital reflected in Table 7 that was allocated to the Bill Management project?

A42. Yes. In 2021, the Company launched a new online bill analyzer that consists of two components, a bill impact analyzer and a bill simulator, that together provide customers with an estimate of those items that impacted their current bill – usage, weather, billing days – along with the ability to simulate their next bill based on usage forecasts, and the impact of any usage reductions they could realize by changing their behavior.

The Commission, in its final order in Case No. U-20836, approved for recovery $2.6 million in capital for the implementation of this new "Bill Management" tool, as reflected in Exhibit A-24, Schedule N8, Page 1, Column b, Line 5. The Company invested an additional $3.4 million in the Bill Management tool in 2022 to address identified defects, to continue to enhance the Billing experience, and to incorporate the ability for the tool to effectively analyze and simulate Time-of-Day (TOD)rates/bills, which were implemented in March of 2023.

Q43. What are the realized and forecasted customer benefits of the identified scope of work funded by the Billing digital self-service capital?

A43. In 2022, customers completed over 6.2 million Billing transactions, with 5.5 million completed in a digital solution (89% DER), and 0.68 million completed through a CR call. In 2023, total completed Billing transactions increased to 6.8 million, however, the number of transactions completed in a self-service solution increased to 6.3 million (92% DER), while those completed through a CR decreased to 0.55 million. This implies that while customer Billing inquiries increased in 2023 due to the TOD implementation, significant numbers of those customers chose to engage in a digital solution to handle their inquiries. In fact, in 2023, over 210,500 customers accessed the Company's online bill management tool, over 483,200 times, and over 113,700 customers used the Company's high bill inquiry VA over 159,300 times, to get answers to questions about their bill.

Given the results achieved to-date, the Company is forecasting that its historical and planned investments in the Billing digital self-service solutions will increase the Billing DER to 94% by 2027, will enable a cumulative decrease of 244,000 calls (2023-2027), and will provide customers with a net cumulative $2.8 million in O&M savings (2023-2027). The annual Billing call volumes and associated O&M savings are included in Exhibit A-24, Schedule N5.

Q44. Which projects support the expansion of the Payment digital transaction?

A44. The Company will invest $4.6 million in a project to enhance and expand the Payment digital self-service solutions over the course of 36-months ending December 31, 2025, as shown on Line 42 of Exhibit A-12 Schedule B5.7.3, and which I have summarized in Table 8 below. See Exhibit A-24 Schedule N3.1 Lines 63-65 for additional project details.

Table 8. Payment Digital Self-Service Capital ($000s)

Line Item	Project Name	Year	Total Capital	Allocated to Payments
42	Payment Web Self-Service	2023-25	$4,553	$4,553

Line No.

Q45. Can you elaborate on the scope of work that is being funded by the Payment digital self-service capital?

A45. Yes. The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 84% 2023 Payment DER (Table 2). However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER significantly reduces call volumes.

In 2023, a minimal of amount (approximately $50,000) of the $4.6 million in Payment Web Self-Service capital was focused on addressing known defects in the Payment digital self-service solutions that were preventing customers from successfully completing their transactions. This investment enabled an increase in the percent of customers who were successfully completing their Payment digital transaction from 76% in 2022 to 79% in 2023. In parallel with its focus on Payment defect remediation in 2023, the Company increased customer awareness of the availability of the Payment self-service solutions and made it easier for customers to access those solutions through clickable links in email notifications and SMS messages.

In 2024-2025, the Company is significantly increasing its capital investment in the Payment digital self-service solutions to improve the Payment digital experience by further increasing the percent of customers who are able to successfully complete their digital Payment transaction, and to improve the experience for customers intending to perform other transactions, as the current Payment digital experience was originally designed and implemented in 2018 as a stand-alone transaction; however, with the increase in digital transactions in Collections and MIMO over the past few years, the Payment solution is being leveraged across multiple transactions. As such, it is important that the Company invest in both the Payment digital solutions, and Payment experience within the Collections and MIMO digital solutions. I have summarized the planned Payment digital solution improvements below.

<u>2024-2025 Payment Digital Improvements</u>

- Redesigning the online web payment center (authenticated version and guest version) to improve the resiliency and the user experience and the user interface.
- Streamlining how other transactions integrate with the payment center (e.g., MIMO & Collections) to improve the user experience and technical implementation process to integrate payments into other transactions.
- Eliminating failure points for both Authenticated Payments (i.e., customers who log-in to their online account) and Guest Payments (i.e., customers who do not log-in or who do not have an online account) that are preventing customers from successfully completing their payment.
- Simplifying the process for Autopay customers to update their saved payment methods, which today requires the customer to unenroll and reenroll in the program and can lead to calls to a CR.
- Implementing more descriptive error messages, so that when customers fail in their attempt to make a payment on the Web, they will know why and can increase the likelihood of success on their next attempt.

Line
No.

Q46. What are the realized and forecasted customer benefits of the identified scope of work funded by the Payment digital self-service capital?

A46. In 2022, the Company handled 32.84 million Payment transactions, of which 26.96 million (82% DER) were completed in a self-service solution, which for Payments includes the Web, Mobile App, IVR, and Kiosk, as well as customers who use Auto Pay and Electronic Funds Transfer (EFT). In 2023, the number of Payment transactions increased to 32.92 million, but at the same time the volume of those transactions completed in a self-service channel also increased to 27.80 million (84% DER).

So, while the number of Payment transactions only increased by 0.2% (60,000 transactions) the number of Payment transactions in 2023 that were completed in a self-service channel increased by over 3% (78,000 transactions). However, the increase of 840,000 digital Payment transactions includes the transition of over 460,000 Payments that in 2022 were made through the mail, but were made electronically through AutoPay in 2023. Therefore, the reduction in Payment call volumes from 2022 to 2023 was a net 280,000 calls (Figure 5).

Given the results achieved to-date, the Company is forecasting that its historical and planned investments in the Payment digital self-service solutions will increase the Payment DER to 85% by 2027, which will enable a cumulative decrease of ~360,800 calls (2023-2027) and provide customers with a cumulative ~$4.1 million in O&M savings (2023-2027). The annual Payment call volumes and associated O&M savings are included in Exhibit A-24, Schedule N5.

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No.

Q47. Are there other Customer IT capital projects that also support the Company's call volume reduction efforts?

A47. Yes. A total investment of $1.4 million, consisting of $0.5 million in 2023 and $0.9 million in 2024 bridge period capital, from the Advanced Analytics Use Cases project shown on Line 18 in Exhibit A-12, Schedule B5.7.3, also supports the Company's call volume reduction efforts. Since $0.4 million of the 2023 bridge period capital has already been approved for recovery in U-20836, the Company is seeking recovery for $1.0 million of 2023 bridge period capital for this project in the instant case. See Exhibit A-24 Schedule N8 Page 2, Column c, Line 3 for details on the capital approved for recovery in U-20836 for the Advanced Analytics (AA) Use Cases project. What follows is a description of the scope of each of the 2023 and 2024 analytics use case as they relate to providing call reduction benefits.

<u>2023 AA Use Case - Scope and Benefits</u>

In 2023, the Company spent $0.5 million in capital to develop an analytics model that uses Natural Language Processing (NLP) technology and Speech Analytics to improve the accuracy with which customer calls are categorized, especially as it relates to those calls that would often be manually categorized as "Other" by the CRs. Through the use of advanced algorithms, we have seen call categorization accuracy improve from 74% to 86%, with most of that improvement related to those calls that would have been previously allocated to the "Other" category being more appropriately categorized into one of the five key transactions. The analytics model is also self-learning so it will be continually updating its categorization algorithm and enhancing the process and its ability to provide even deeper insight over time into customer calls and call patterns.

By dispositioning calls to the appropriate call categories, the Company is gaining greater visibility into the total volume and most common reasons for calls from customers across each of the five key transactions. This allows us to identify process and policy improvements with each transaction that will provide incremental call volume reductions. Through 2027, the use of the analytics model is forecasted to provide a cumulative incremental call volume reduction, beyond what is expected from our digital self-service projects, of ~30,000 calls, for total sustained O&M savings of ~$340,000. The call volume and O&M cost reduction is reflected in Exhibit A-24, Schedule N5 (Page 2, footnote 7).

2024 AA Use Case - Scope and Benefits

In 2024, the Company is investing $0.9 million to build an analytics model that will identify the precise touchpoints and scenarios in the various customer interactions that either cause a customer to call, or that result in a failure to successfully complete their interaction in a digital self-service solution. This first requires a complete mapping of the customer touchpoints for each customer interaction, followed by advanced analytics modeling and tools that will uncover the underlying reasons of why a customer chooses to call, as opposed to using a digital self-service channel, and why a customer who started in a digital self-service solution had to call the Company to complete their interaction. These efforts are expected to reduce 17,500 additional calls in 2024 through 2025, resulting in cumulative and sustained O&M savings of ~$200,000. These call volume and the O&M cost reductions are reflected in Exhibit A-24, Schedule N5 (Page 2, footnote 8 and 9).

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Q48. Is the Company requesting cost recovery of any previously approved Customer IT capital project investments in the instant case, and if so, why?

A48. Yes. As set forth in Exhibit A-24, Schedule N8, there is $13.3 million in 2022-2023 capital, across eight projects (Page 2, Columns b through d, Line 1, Lines 5-11), that I am sponsoring in my testimony in the instant case, of which $5.7 million (Page 2, Columns b through c, Line 3 and Line 13) was previously approved by the Commission for cost recovery in Case No. U-20836. Additionally, there is $5.7 million in 2021 digital self-service capital, across three projects (Page 2, Column a, Line 13), that were also previously approved by the Commission for recovery in U-20836, but that is not reflected in Exhibit A-12, Schedule B5.7.3 of the instant case.

Despite their prior approval of this $11.4 million in 2021-2023 capital, the Commission in its final order in U-21297 disallowed for recovery the entirety of these projects based on arguments made by the Detroit Area Advocacy Organizations (DAAOs). Because the capital investments set forth in Exhibit A-24, Schedule N8 were previously approved for cost recovery in Case No. U-20836, and the Company relied on such approval when spending the capital, it is appropriate for the Commission, in the instant case, to authorize cost recovery of these capital investments to rectify the inadvertent retroactive disallowance that resulted from the final order in Case No. U-21297.

Q49. Is the Company providing a detailed cost-benefit analysis for its Digital Self-Service projects?

A49. Yes. The Company is providing a Net Present Value (NPV) analysis of its digital self-service projects, the details of which can be found in Exhibit A-24, Schedule N6.

Q50. Please describe how the Company models the NPV for its Digital Self-Service projects?

A50. The NPV model determines the annual cost to customers that results from the Company's recovery of the digital project cash outflows through the ratemaking process, which is referred to as the "revenue requirement customer costs." This includes the revenue recovery impact of the initial capital project costs, the project cost-to-achieve O&M, and all of the ongoing sustainment capital and trailing O&M costs. The model then calculates what is referred to as the "revenue recovery customer savings," which is the difference between the annual digital project call volume reduction O&M savings, and the annual project O&M costs, which includes the digital project cost-to-achieve O&M and any ongoing project trailing O&M costs.

The difference between the revenue requirement customer costs, and the revenue requirement customer savings, determines the "net annual revenue recovery" cost or (savings) to customers, which the model then discounts back to today's dollars to determine the NPV to customers of the digital projects. A negative NPV implies the projects are value creating for customers (i.e., saves customers money), while a positive NPV would imply the projects are not value creating for customers (i.e., costs customers money).

Line No.

Q51. Which capital investments are included in the NPV model?

A51. The NPV model, as reflected in Exhibit A-24, Schedule N6, includes all 2022-2025 capital projects that support the enhancement and expansion of the Company's digital self-service solutions for each of the five key transactions, whose scope and benefits are described in Part 4 of my testimony. Also included in the NPV model are the previously described 2023 and 2024 AA Use Case capital project investments, which as discussed are also intended to reduce call volumes and deliver O&M savings for customers. Finally, the NPV model also includes $12.0 million in 2021 digital self-service project capital, which was sponsored in my testimony in DTE Electric Case No. U-21297 (MJH-41, Table 2).

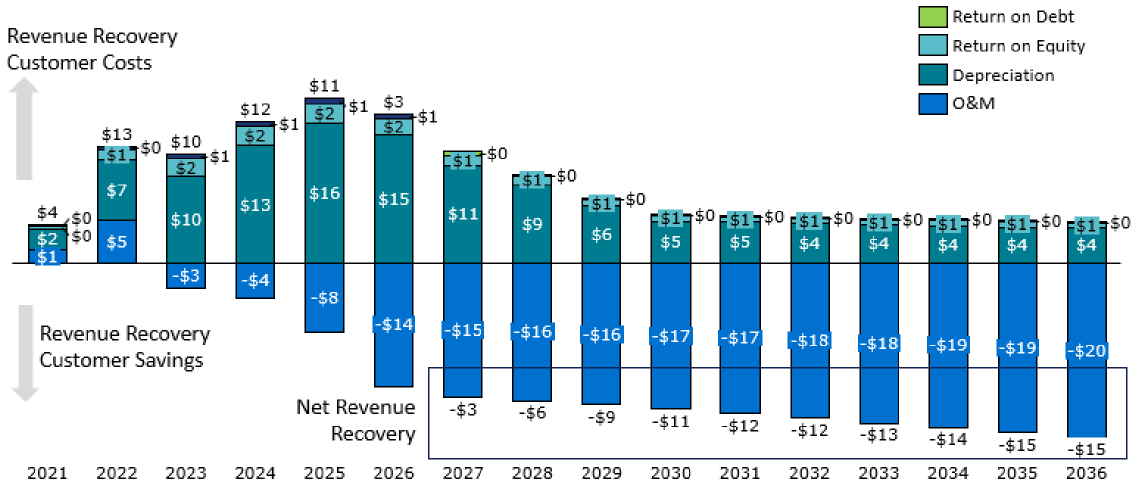
Q52. Why is the Company including 2021 digital capital in its NPV analysis if it is not included in the historical, bridge, or test period capital in the instant case?

A52. The 2021 digital investments are contributing to the realized and ongoing reductions in call volumes, which are reflected in the NPV model and included in the NPV calculation. As such, it would be disingenuous to include the call volume reduction savings in the NPV analysis, but to exclude the revenue recovery cost to customers of the 2021 capital investments, as doing so would inflate the NPV.

Q53. What is the NPV of the Company's digital self-service projects?

A53. The NPV of the Company's digital self-service capital projects has been determined to be a negative $5.6 million, which confirms that the digital self-service investments are value creating for customers, as reflected in Exhibit A-24 Schedule N6, Line 23, Column (h). I am providing a summary of the results of the NPV analysis in Figure 8.

Figure 8 - Digital Self-Service Project NPV ($ millions)



As seen in Figure 8, customers start to realize net revenue recovery savings in 2027 (i.e., current year revenue recovery savings are greater than current year revenue requirement costs). These annual net savings continue to grow to an annualized $15.3 million by 2036 and are sustained in perpetuity as reflected on Exhibit A-24 Schedule N6, Line 22, Columns n through w.

I would note here that the $12.0 million in 2021 digital self-service capital included in the NPV analysis, was part of the $51.3 million in total digital self-service capital for which the Company was seeking recovery in U-21297, and which was subsequently disallowed for recovery in its entirety by the Commission in its final order in that case. As such, the Company believes that its analysis conservatively calculates the NPV of the digital self-service projects because customers are currently not incurring the associated revenue recovery costs of the $12.0 million in 2021 capital. Should the Commission authorize recovery of the previously

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discussed $5.7 million in 2021 digital self-service capital originally approved in Case No. U-20836 (See Exhibit A-24 Schedule N8, Page 2, Column a, Line 13), customers would still only be incurring the revenue recovery cost of less than half of the $12.0 million in 2021 digital capital.

Part 5. Operational Efficiency Projects

Q54. What is included in this section of your testimony?

A54. This section of my testimony will include a discussion of projects that align with enabling operational efficiencies and stability in the Contact Center, Billing, and the Revenue Management and Protection (RM&P) groups. I will also discuss projects in which the Company is leveraging advanced analytics to capture operational efficiencies that improve the customer experience and provide cost savings. Additionally, I will discuss how we are also investing capital in projects that improve the quality and efficiency of the Customer CR&B system, and with which the Company implements its Customer IT projects.

Q55. Can you please describe projects that deliver operational efficiencies in the Contact Center?

A55. Yes. The Company is investing a total of $2.5 million in capital, consisting of $2.1 million in the 2023-2024 bridge period and $0.4 million in the 2025 test period, in two projects that will enhance the ability of the Contact Center to reduce the Average Handle Time (AHT) of calls from customers, and that will improve customer accessibility to the telephony systems during peak call times, such as during a major storm event. These projects are both included in Exhibit A-12, Schedule B5.7.3, and are summarized below.

1. Line 30 – Contact Center Enablement

The Commission previously approved, in its final order in Case No. U-21297, $0.7 million in 2023-2024 capital for the Contact Center Enablement project, which enhances the Customer Relationship Management (CRM) system for the Collection transaction to reduce its AHT. The Company's actual spend for this project was $1.3 million in capital .. The incremental spend of $0.6 million was due to emergent scope in 2023 that resulted from the complexity of the required enhancements, which necessitated engaging the services of additional SAP consultant resources. Additionally, in 2025, the Company is forecasting to spend another $0.4 million to make similar enhancements in CRM to reduce AHT across the other key transactions. This incremental capital is reflected in Exhibit A-24 Schedule N9, and brings the total capital spend for this project to $1.7 million.

Therefore, in the instant case, the Company is seeking recovery of a total of $1.0M in incremental capital for this project, which includes the incremental $0.6 million that was required to complete the 2023 Collection scope, plus the additional $0.4 million in capital to reduce the AHT of the other key transactions support. See Exhibit A-24 Schedule N3.1 Line 18 for additional project details.

2. Line 45 – SIP in Contact Center

The efficiency with which the Company manages and maintains its telephony systems, including the IVR, significantly impacts the accessibility of these systems for our customers. This is especially true in periods of increased customer usage, such as during a significant customer outage event or during the application of required software patches and upgrades.

The Commission previously approved, in its final order in Case No. U-21297, $1.7 million in 2022-2024 capital for the SIP in Contact Center project. The Company actually spent $0.9 million in 2023 to complete the project, as reflected in Exhibit A-12, Schedule B5.7.3. The $0.8 million reduction in total capital, versus what was previously approved, is because the Company was able to leverage cost synergies gained from the implementation of other projects, which reduced the time, effort, and resources required. As such, there is no incremental capital associated with this project for which the Company is seeking recovery in the instant case.

Q56. How is the Company investing capital to improve operational efficiency in Billing?

A56. In October 2022, DTE launched a new Meter Data Management (MDM) system to replace an outdated and unsupported DTE IT solution. Since that time, the Company has identified opportunities to enhance the new MDM solution to reduce billing exceptions, reduce manual work, improve forecasting, and prevent delayed bills for its largest commercial and industrial customers. To fund these enhancements the Company is investing $1.8 million in 2025 test period capital in the Meter Data Management (MDM) Stabilization project, as reflected on Line 23 of Exhibit A-12 Schedule B5.7.3.

These enhancements will reduce by 80% the number of manual touches (~12,000) currently required to remediate exceptions and prevent delayed bills, providing

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~$100,000 annually in O&M savings. The MDM project will also reduce potentially higher energy market settlement charges due to forecasting errors from estimated commercial and industrial load. See Exhibit A-24 Schedule N3.1 Line 42 for additional project details.

Q57. How is the Company investing capital to improve operational efficiencies in its RM&P group?

A57. The Company is investing $0.4 million in 2025 test period capital to improve the management of instances of theft and fraud with the Never Billed Accounts due to Theft / Fraud project (Exhibit A-12, Schedule B5.7.3, Line 24). The Commission previously approved, in its final order in Case No. U-21297, $0.4 million in 2024 capital for this project. However, the project has been re-timed to 2025 to provide capacity for other more urgent IT projects. The Company is seeking continued recovery of this capital in the 2025 test period in the instant case.

As discussed in U-21297, this project creates new functionality in the core billing system that will provide a new screen for the Revenue Management and Protection (RM&P) Exceptions Team to utilize when a customer needs to be billed for theft, ID fraud, or bankruptcy, and the normal billing process cannot be used. As no bill is generated today, the account does not progress through the collection (SAP dunning) process. Since the SAP CR&B system went live in April 2017 through March 1, 2024, ~$1.6 million in charges have accrued on customer accounts that have not been billed and are aging in active arrears. See Exhibit A-24 Schedule N3.1 Line 61 for additional project details.

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Q58. How is the Company leveraging Advanced Analytics to capture operational efficiencies and optimize customer programs and processes to reduce uncollectible expense (UCX) and O&M costs?

A58. DTE is investing in analytics resources and technologies that will provide greater insight into customer segments, behaviors, and improving the customer experience. To that end, the Company is investing $6.6 million in capital, consisting of $1.1 million in the 2022 historical period, $2.5 million in the 2023-2024 bridge period, and $3.0 million in the 2025 test period, in the Advanced Analytics (AA) Use Cases project as shown on Line 18 of Exhibit A-12, Schedule B5.7.3.

The Commission, in its prior order in U-20836, previously approved $1.5 million in 2022-2023 capital for investment in Advanced Analytics use cases, to enable the Company to gain a deeper understanding of our customers, customer segments, and customer behaviors and preferences. See Exhibit A-24 Schedule N8 Page 2, Columns b through c, Line 3 for details. As such, in the instant case, the Company is seeking recovery of an additional $5.1 million in capital for the implementation of new analytics use cases, which includes $1.0 million in capital for the 2023 AA use case ($0.1 million) and the 2024 AA use case ($0.9 million) that I discussed in Part 4 of my testimony because they support achievement of the Company's call volume reduction commitments and provide O&M cost savings in 2023-2027. The remaining $4.1 million in capital, for which the Company is seeking recovery, will be allocated to the 2024 and 2025 AA use cases to be described below that will leverage advanced algorithms and machine learning to optimize customer programs and processes to reduce uncollectible expense (UCX) and O&M costs. Specific capital investment dollars and the customer benefit provided by the project is

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described and delineated for each individual 2024 and 2025 AA use case, just as they were for each 2023 and 2024 AA use case that contribute to call volume reduction described in Part 4. See Exhibit A-24 Schedule N3.1 Lines 3-6 for additional project details.

1. <u>2024 Energy Assistance AA Use Case – $1.1 million</u>

The Company is investing $1.1 million in 2024 bridge period capital to develop a machine learning model to optimally allocate available energy assistance paired with Energy Waste Reduction (EWR) to eligible low-income customers. Today, energy assistance is available to DTE Electric low-income customers whose balances are past due or who otherwise qualify for assistance. This support assists customers in paying down their arrears and can help them avoid a disconnection due to non-payment in the short-term. However, for a more comprehensive, long-term approach to assisting them in reducing their bills and managing their arrears, a combined offering of energy assistance along with EWR funding would be more effective. This AA use case funds development of a machine learning solution to identify eligible customers for both energy assistance and EWR. When the model indicates eligibility for both programs, a bundled offering will then be extended to these low-income customers, who may not have been aware of their eligibility to access both programs and how to apply for this support.

While traditionally customers seeking energy assistance funds must reach out to DTE or third-party agencies to start the process, instead we would be able to leverage the machine learning model to match customers with EWR and energy assistance program(s) that best fit their needs and circumstances, simplifying the process. Through a more effective and optimal means of distributing energy assistance and helping our low-income customers to better manage their bills with EWR, we estimate that this offering can reduce customer arrears and UCX by $300,000 in 2024 through 2025.

2. 2025 AA Use Case – Reducing MPSC Complaints – $1.0 million

The Company is investing $1.0 million in 2025 test period capital to develop a machine learning model to understand the drivers underlying Customer Service MPSC complaints and make recommendations for improvements in our key transactions, especially in Collection and Billing, which generate ~80% of Customer Service complaints. Collection and Billing calls also have longer call handle times at 12.6 minutes and 11.2 minutes, respectively, as compared to the average of 10.5 minutes across all call types. The Company will leverage the model's output to anticipate customer pain points that may be leading to their dissatisfaction and frustration, and proactively reach out to these customers to understand their concerns and resolve their issue before it becomes a MPSC complaint. The model's output will also be integrated into our customer systems so that if a customer who is likely to complain calls, the CRs can more swiftly escalate the customer's issue for resolution. We anticipate that the actions taken to address the drivers of customer complaints through process improvements in our key transactions and taking proactive steps will reduce 110 or ~15% of Customer Service MPSC Complaints (based on 2023 data) over a five-year period starting in 2026, and will provide operational efficiencies by reducing the volume of complaints and better dedicating the same resources to focus on effectively resolving the customers pain points that lead to complaints.

3. <u>2025 AA Use Case - Automating CR Notes – $2.0 million</u>

The second 2025 AA use case will be focused on developing advanced analytics models designed to reduce the average handle time (AHT) of calls by automating the notes taken by CRs during or after a call. Currently, CRs manually enter notes into CRM for ~30% of handled calls, particularly for inquiry calls as it provides visibility into why the customer called. While these notes are valuable for follow-up tasks, addressing subsequent customer calls, and understanding the reason for calls when there is no transaction completed, this process adds to AHT, which translates into Contact Center O&M costs, longer wait times, and potentially lower service levels.

Using advanced analytics algorithms that leverage natural language processing to automate the note-taking process by analyzing call transcripts, the Company can reduce AHT by ~20 seconds for 30% of the calls in which the CR enters notes for an estimated savings of ~$300,000 annually starting in 2026 and in perpetuity. Automating the CR note-taking process also provides other benefits, such as more comprehensive notes than those entered manually, enabling us to analyze customer calls and look for opportunities to improve the quality of their call experience or deflect calls to self-service.

Q59. What IT efficiency projects are intended to improve the quality and efficiency of the Customer CR&B system and with which the Company develops and deploy Customer IT projects and reduce system downtime?

A59. The Company is investing $9.1 million in 2022 historical period, 2023-2024 bridge period, and 2025 test period capital in five IT efficiency projects that will be discussed in the order they appear in Exhibit A-12, Schedule B5.7.3. Together, these projects are intended to:

- Reduce the frequency and associated remediation and monitoring costs of CR&B system outages;
- Remediate defects and make minor enhancements to the CR&B system;
- Accelerate the development, quality assurance review, and testing of Customer IT projects; and
- Ensure the up time of customer systems and applications through optimization of the flow of work and load on the system.

The Commission previously approved, in its final order in Case No. U-21297, $8.3 million in 2022-2024 capital for these projects. The $0.8 million increase in capital, versus what was previously approved, is a result of the net impact of increases and decreases in the individual projects, which I describe below.

1. <u>Line 19 – Automated Application Monitoring Enhancement</u>

The Company is investing a total of $2.7 million in capital, consisting of $1.5 million in the 2022 historical period, $0.3 million in the 2023 bridge period, and $0.9 million in the 2025 test period, in this project. The Commission, in its prior order in Case No. U-21297, previously approved for recovery a total of $3.3 million in 2022-2024 capital for this project.

While the total capital cost of $2.7 million for this project is $0.6 million less than the $3.3 million in capital that was approved for cost recovery in U-21297, $0.9 million of capital has been to re-timed from 2024 to 2025, which will allow us to evaluate the performance of the monitoring that has been implemented in 2022-2023. As such, while the Company is not seeking recovery of additional total capital for this project, it is seeking in the instant case recovery of the $0.9 million in the 2025 test period, which will complete the originally approved scope, and expands the scope to include implementation of the Focus Build, Focus Insights, and Customer Code Management modules.

Focus Build manages requirements and software development for large, agile innovation projects. Custom Code Management is the central point of access for all functions that are used to monitor and manage the complete lifecycle of custom developments from requirement to retirement. Focus Insights manages Focus Build and distributes powerful customer-specific dashboards in minutes providing a state-of-the-art user experience. See Exhibit A-24 Schedule N3.1 Line 9 for additional project details.

2. <u>Line 21 – Customer Relationship and Billing Program Enhancement</u>

The Company is investing total capital of $4.0 million in enhancements to the CR&B system that support improved customer experiences across the five key transactions, which consists of $2.8 million in the 2022 historical period, and $1.2 million in the 2023 bridge period. The Commission in its final order in Case No. U-21297, previously approved $2.0 million in 2022 capital for this project. The additional $2.0 million in capital, for which the Company is seeking recovery in the instant case, results from increased spending of $0.8 million in 2022 to fund emerging enhancement opportunities, and $1.2 million of new capital spend in 2023, which funded newly identified opportunities for enhancement. See Exhibit A-24 Schedule N3.1 Lines 25-26 for additional project details.

The majority of these 2022-2023 CR&B enhancements were related to the MIMO, Collection, and Billing transactions, and were intended to increase First Contact Resolution (FCR), which is a measure of the Company's ability to address a customer's request or inquiry, over the phone or in a digital channel, on the first try, without the customer having to reach out repeatedly. Overall, these investments resulted in an increase in the average FCR, across the five key transactions, from 84% 2021 to 86% in 2023. With over 43 million transactions completed each year, every 1% increase in FCR impacts the experience of a significant number of customers, making it easier for them to complete their transaction, and avoiding the frustration that comes with having to repeatedly contact the Company to resolve their inquiry or request. Below are examples of the types of enhancements funded by the total 2022-2023 capital for each transaction.

<u>2022-2023 MIMO CR&B Enhancements</u>

A total of 99 defects and enhancements were remediated and implemented in 2022-2023 for the MIMO transaction, which enabled an increase in the MIMO FCR from 87% in 2021 to 89% in 2023, with some of the more significant examples described below.

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- Updated the arrangement of Customer Relationship and Management (CRM) screens used by the Customer Service Representatives (CRs) – providing a better call handling experience for customers and lower AHT.
- Created new notification templates for Force Move-Out customers, ~40% of the move-out population and for whom we have never sent notifications.
- Updated the WISMO (“Where is my order?”) refresh rate so that the MIMO Order Tracker provides near real-time data from 15 minutes to 1 minute.
- Incorporated “clickable” links and information bubbles for the CRs through the MIMO screens in CRM – reducing customer wait times and AHT.
- Established the ability to Web register customers during the MIMO process in CRM – at inception we observed a 200-300% daily increase.
- Enhanced the system to perform a check so that a customer is not erroneously assigned more than one contract account at the same premise / address when the account is being created, eliminating the risk of customers receiving multiple billing statements.
- Supported the new VA functionality to allow customers to create a Move-in or Move-out using the VA, reducing the number of customers transferred to a CR.
- Created functionality to allow customers starting service with a known lease-end date to schedule a Move-out and not have to call DTE again.
- Created functionality within CRM that allows a CR to click on a link for additional instruction on how to complete the customer transaction. Reduces handle time per call and prevents unnecessary escalations.
- When a customer transfers service within the DTE service territory, we will now automatically transfer their LSP plan with them. This prevents additional calls from the customer to transfer their plan.

- Removed barriers that made web registration more difficult for customers, allowing them to perform future transactions in self-service channels.
- Added error codes to CRM that allowed us to better diagnosis and remedy VA failures so that the process can work more frequently for customers.

2022-2023 Collection CR&B Enhancements

A total of 150 defects and enhancements were remediated and implemented in 2022-2023 for the Collection transaction, which enabled an increase in the Collection FCR from 78% in 2021 to 79% in 2023, with some of the more significant examples described below.

- Updated the 65 New Closed Loop emails and added SMS to keep customers informed of where they are in the collection process (SAP Dunning), improving our communications with the customer.
- Upgraded the Payment Kiosk to accept payments on customer accounts that were disconnected for non-payment.
- Automated Senior Flag to update when a customer reaches the age of 65. This flag protects Seniors from disconnection due to non-payment as part of the Winter Protection Plan (WPP), annually from November 1 through March 31.
- Refinements to optimize the collection process (SAP Dunning) to reduce growth in arrears and potential write-offs and UCX.
- Notification enhancements to proactively give customers information regarding their accounts, landlord accounts, payment plan updates, and payment extension status.

- CRM enhancements to allow transactions to function properly including customer refunds, completing theft service orders, payment allocations, ensuring accurate LIA/RIA enrollment status, and low-income verification.
- Web/VA work to ensure we are offering customer appropriate solutions for Payment extensions and Payment Agreements, and to update customers of lock status so they know they are not at risk of a disconnect due to non-payment.
- Updated the cash only flag logic so that good paying customers are not impacted and forced to change payment method.

2022-2023 Billing CR&B Enhancements

A total of 50 defects and enhancements, some related to TOD, were remediated and implemented in 2022-2023 for the Billing transaction, with some of the more significant examples described below. From 2021 through 2023 Billing FCR has held steady at 75% despite remediating defects from the 2023 full implementation of Time-of-Day rates. Some of the more significant examples described below.

- Billing system "sum check" calculation, as well as usage check calculations so that customers do not receive bills with substantial errors.
- Updates to CRM to increase the visibility of customers enrolled in a billing program and or payment plan to include Flexible Due Date, Reduced Bill Frequency, My Bill, My Time, and CoolCurrents.
- Ability to compare DTE Gas rates versus an Alternative Service Provider's rate.
- Improved the productivity of internal business users when querying and viewing the status and statistics for Billing business exceptions.

- Banner Letter enhancements to provide customers detailed information regarding an account's adjustments or billing corrections.
- Supported CRM enhancements related to MPSC rate case implementation to ensure billing accuracy and to help customers enroll and unenroll in rates more efficiently such as for the Dynamic Peak-Pricing (D1.8) rate.
- Enhancements to reduce the manual touches need during the monthly billing process for our Major Accounts (Assigned Customer) Team.
- Enhancements to e-bill process to increase customer adoption rate and improve the customer experience.

3. <u>Line 22 – IT Application Environments Enhancement</u>

The Company invested a total of $0.5 million in capital in the IT Application Environments Enhancement project, which consisted of $0.2 million in the 2022 historical period, and $0.3 million in the 2023 bridge period, to create a new Quality Assurance (QA) environment. The total capital cost for this project included in the instant case, is $0.4 million less than the $0.9 million in 2022-2024 capital that was previously approved for cost recovery by the Commission in Case No. U-21297.

The project was completed in 2023, a year ahead of schedule and with favorability to its budget, due to efficiencies that were realized by the selected vendor. As such, although DTE Electric is not seeking recovery of any incremental capital for this project in the instant case, the Company is including the project here to explain the significant favorable variance relative to what was approved for recovery.

4. <u>Line 25 – Supporting Capabilities Test Data and Test Data Management</u>

The Company invested the net amount of $0.9 million in capital in the 2022 historical and 2023 bridge period to establish a process to generate automated test data and test scripts. The Commission, in its final order in Case No. U-21297, approved for recovery $1.2 million in capital for this project. The reason for the reduced capital spend of $0.3 million is that because during the execution phase, the anticipated need for additional infrastructure (servers), and corresponding labor, were found to be unnecessary. Although DTE Electric is not seeking recovery of any incremental capital for this project in the instant case, the Company is including the project here to explain the favorable variance relative to what was approved for recovery.

5. Line 26 – Transform and Modernize PO Architecture

The Company will invest $1.0 million in 2025 test period capital to transform and modernize the Process Orchestration (PO) architecture to alleviate system bottlenecks due to network traffic and growing functionalities in the CR&B system. The Commission, in its final order in Case No. U-21297, approved for recovery $1.0 million in 2024 capital for this project. This project has since been rescheduled into 2025, and as such, we are including it here as part of the Company's request to approve this project for recovery in the 2025 test period in the instant case. Below is a summary of the scope of the project, along with an updated view of the associated customer benefits, which have been determined to be more significant than originally forecasted.

This project remains critical. As the Company enables more capabilities in its customer channels and the CR&B system, it creates additional stress and burden for the PO to ensure increasingly complex jobs and functions perform as expected. During periods of high traffic, such as during a storm or in the fall with the influx of college move-ins, the Company's transactional system and digital channels must scale up to handle the additional workload or risk an unplanned system outage. By upgrading the PO to a more robust architecture, DTE Electric will be able to reduce unplanned system outages that disrupt the Company's ability to serve customers either digitally or through the Contact Center.

While the system is typically back up in ~3 hours during an unplanned outage, it takes at least eight hours to identify the root cause and implement a longer-term fix to stabilize the system. The cost of CRs who wait for the system to be restored during unplanned system outages could be considerable. If it takes ~3 hours for the system to come back up, assuming we are able to reduce unplanned system outages from 10 to 3 by 2028, by multiplying this idle / wait time by the average number of CRs per year between 2026 and 2028 and the hourly labor cost of a CR, this project can reduce the O&M cost of CR wait time by ~$310,000. See Exhibit A-24 Schedule N3.1 Line 87 for additional project details.

<u>Part 6. Projects that Enhance Customer Interactions</u>

Q60. Can you describe the Company's rationale for investing capital in projects that will enable "Enhanced Customer Interactions"?

A60. The Company's strategy to enhance customer interactions is simple – improve the customer experience and the effectiveness and efficiency with which the Company manages customer interactions, by prudently investing in capital projects that enable end-to-end monitoring of customer interactions, which provide customers and employees full transparency into the status of these interactions, and that improve the quality of the data and information provided to customers during these interactions.

Q61. Which of the capital projects you are sponsoring in your testimony are intended to "Enhance Customer Interactions"?

A61. There are five projects I will discuss in my testimony that are intended to Enhance Customer Interactions, three of which are included in Exhibit A-12, Schedule B5.7.3, which I am sponsoring, and two of which are included in Exhibit A-12, Schedule B5.4 Technology and Automation, which is co-sponsored by Company Witness Hartwick (see below).

<u>Exhibit A-12, Schedule B5.7.3</u>

- Line 31 – Customer Closed Loop Development
- Line 33 – Customer Service Communications – Phase 2
- Line 35 – Error Free Communication – Outage Status

<u>Exhibit A-12, Schedule B5.4, Distribution Plant - Technology and Automation</u>

- Page 18 – Line 33 – Operational Technology and EFC
- Page 18 – Line 40 – Other Modernize Grid Management

Q62. Can you describe the Company's investment in the Customer Closed Loop Development project?

A62. Yes. The Commission, in its final order in Case No. U-21297, approved for recovery $1.4 million in 2023-2024 capital for this project. The Company's actual investment totaled $1.8 million in capital in the Customer Closed Loop Development project, consisting of $0.3 million in the 2022 historical period, and $1.5 million in the 2023 bridge period, as shown on Line 31 of Exhibit A-12, Schedule B5.7.3. The 2022 historical spend of $0.3 million was previously approved in Case No. U-20836 as shown in Exhibit A-24 Schedule N8 on Page 2, Column b, Line 22.

The $0.4 million in additional capital the Company spent on this project, relative to what was approved for recovery in U-21297, is due to the $0.3 million in capital the Company spent in 2022, which as stated was previously approved in Case No. U-20386, but was subsequently disallowed in U-21297 due to being part of the $51.3 million in digital self-service projects, and which was used to complete the scope of work for the MIMO and Collection transactions, plus the incremental spending of $0.3 million in capital in 2023 to complete the scope of the Billing and Payment Closed Loop notifications, which was offset by $0.2 million in 2024 capital that was previously approved in U-21297 but that is no longer required. As such, the Company in the instant case is seeking recovery of an additional $0.4 million in capital for this project. Included below is the 2023 scope and benefits realized from the incremental investment in the Billing and Payment Closed Loop notifications.

The intent of the investment in Closed Loop Billing and Payment notifications was to provide customers greater visibility into their Billing and Payment interactions, to share with them clear and concise communications related to those interactions, and to provide them clickable links that would allow to track the status of these interactions in a digital self-service solution. Below I describe some of the Closed Loop Notifications that were enhanced or newly developed with the 2023 investment. See Exhibit A-24 Schedule N3.1 Lines 20-21 for additional project details.

Billing Closed Loop Notifications

All Billing notifications had an update component (i.e., SMS function added) or were newly developed in this project. The new Closed Loop notifications were added where the customer would benefit from more visibility into their billing transaction. One such update was with the Flexible Due Date (FDD) Process with manual communications. This was addressed by automating all FDD communications via email or SMS. This notification informs customers that their request for Flex Due Date has been received and provides updates throughout the process (received, being reviewed, eligible, or ineligible). This level of visibility either did not exist for customers before the project or was being sent inconsistently. Below is the list of Billing Closed Loop notifications that were updated or newly developed.

- BudgetWise Billing enrollment / unenrollment
- eBill enrollment / unenrollment
- eBill ready to view notifications.
- Flexible Due Date request
- Meter tests updates and status
- Billing investigations status

- BudgetWise Billing Program status

Payments Closed Loop Notifications

All Payment notifications were reviewed for completeness and accuracy in their messaging and to incorporate modern language as advised by Corporate Communications. New Closed Loop notifications were added where the customer would benefit from more visibility into their payment transaction, such as for Autopay where there was not an email and SMS notification previously for Autopay withdrawals. The new AutoPay notifications informed customers if the AutoPay did not withdraw (for reasons described in the notification) and that a manual payment would be required. This visibility did not exist for customers before the project. Through our voice of the customer surveys, customers indicated that notifications were important for communicating completion and confirmation of their payment status. Below is the list of Payment Closed Loop notifications that were updated or newly developed.

- Payment due reminders
- Payment cancelled
- Payment past due reminders
- Payments declined
- Credit card expiring
- Autopay withdrawal issues

Line No.

As with MIMO and Collection Closed Loop notifications, the Billing and Payment notifications are expected to reduce customer calls and increase FCR and customer satisfaction.

Q63. Can you describe the Customer Service Communications – Phase 2 project?

A63. Yes. The first phase of the Customer Service Communications was approved for recovery in Case No. U-21297, which included $3.3 million in capital for the implementation of a new notification platform – Message Broadcast – the scope of which was completed in 2023. The Company, in the instant case, is seeking recovery of $2.0 million in 2024 bridge period capital, as reflected in in Exhibit A-12, Schedule B5.7.3, Line 3, to complete Phase 2 of the project, which includes the migration of 99% of all customer notifications to the new Message Broadcast platform, and the leveraging of the new platform to enhance the quality and effectiveness with which we communicate with customers. This includes the ability to create, customize, catalog, and store customer notifications with delivery confirmation, so that we have visibility into which customers did not receive which notifications, and the use of the platform's tools to ensure the integrity of the customer contact data, to quickly create Messages On Demand (MODs) by an assortment of methods, including list, zip code, electrical device, and geography, and to be able to provide customers the ability to communicate with us via SMS/texting. See Exhibit A-24 Schedule N3.1 Line 28 for additional project details.

Q64. Can you provide an overview of the Company's EFC – Outage Status initiative?

A64. Yes. In simple terms, the Company determined that it needed to transition from a "work-based" power status system to a "premise-based" system, with premise being the Company's term for a customer's home or business location. The Company's "work-based" system aggregates outage data from the AMI network, input from field crews, and customer calls, and couples this data with the electrical system equipment hierarchy to determine outages at a circuit level. The work-based system does not focus on tracking and monitoring individual customer outages. Creation of a "premise-based" system allows the Company to leverage its AMI infrastructure to monitor individual premise outage data and restoration status, and provide power status and notifications at the customer level. This significantly enhances the relevance and quality of the information and communications provided to customers and improves the customer Outage experience.

There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already existed, some that existed but needed to be modified, and some that were completely new:

1. Outage Management System (OMS) – Existing system that processes outages with work-based calculations, using field crew job and equipment data.
2. AMI – The Company's Automated Metering Infrastructure (AMI), which supplies voltage, Power Outage Notifications (PONs), and Power Restoration Notifications (PRNs) into Premise Power Stats (PPS—see below) for processing premise-based calculations.

3. ESRI's ArcGIS – Maintains the equipment hierarchy for the electric grid and uses the hierarchy to map equipment outages to the customers attached to that equipment.
4. Event Hub – A new system that streams the outage events from OMS into the new PPS system.
5. Premise Power Status (PPS) – A new system that translates work-based outage information from OMS and the AMI meter data into premise-based outage information.
6. "Where is My Order" (WISMO) – The Company's order tracking system, which for Outages integrates information from PPS to allow for tracking of individual customer outages, and to trigger the appropriate notifications to customers.

Q65. Can you provide an update on the amount of capital the Company has invested, and is planning to invest, in its Error Free Communications (EFC) – Outage Status initiative?

A65. Yes. The Company in its DTE Electric U-21297 rate filing, requested recovery of $35.9 million in 2021-2024 capital to support the modification of the above systems to support the EFC Outage Status initiative, of which $29.7 million was approved by the Commission in its final order in that case. The Company is now forecasting to spend a total of $50.0 million in total capital from 2022-2025, which excludes $2.4 million in 2021 capital previously requested and approved for recovery in U-21297. Exhibit A-24, Schedule N7 provides a complete breakdown of how the total $50.0 million in capital is being allocated across the back end "Core" systems, and front end "Customer-Facing" systems, including the total amount of capital being invested in each system component or workstream, and the portion of the total capital that was previously approved for recovery by the Commission in its final order in Case No. U-21297. Additional project details are in Exhibit A-24 Schedule N3.1 on Lines 30-32.

Q66. How much total capital is allocated to the Core systems to support the EFC – Outage Status initiatives?

A66. The Company is investing a total of $14.2 million in the EFC Core systems, consisting of $8.4 million in 2022 historical period that was approved for recovery by the Commission in its final order in Case No. U-21297, plus an additional $5.2 million in 2023-2024 bridge period capital, and $0.6 million in 2025 test period capital, which were not previously requested for recovery. A detailed summary of the capital allocated to the Core systems, including those amounts that were previously approved in Case No. U-21297, can be found in Exhibit A-24 Schedule N7, on Pages 1-2.

Q67. How much total capital is allocated to the Customer-Facing systems to support the EFC – Outage Status initiatives?

A67. The Company is investing a total of $35.8 million in capital in the Customer-Facing systems to support the EFC – Outage Status initiatives, which consists of $14.9 million in 2022 historical period capital, and $20.9 million in 2023-2024 bridge period capital. Of the total $35.8 million in capital, $19.0 million was previously approved for recovery by the Commission in its final order in Case No. U-21297, including $7.0 million in 2022 historical capital, and $11.9 million in 2023-2024 bridge period capital. The $35.8 million also includes the $6.3 million in 2022 capital allocated to the enhancement of the Outage digital solutions, as described in

Part 4 of my testimony. A detailed summary of the capital allocated to the Customer-Facing systems, including those amounts that were previously approved in Case No. U-21297, can be found in Exhibit A-24 Schedule N7, on Pages 3-4.

Q68. To-date, what improvements in Outage metrics have been realized through the Company' investments in its EFC – Outage Status initiative?

A68. In addition to Outage call volume reductions enabled by the $6.3 million in 2022 EFC – Outage Status initiative capital, which was allocated to the enhancement of the Outage digital solutions as described in Part 4 of my testimony, the Company has realized improvements in 1) the timeliness and accuracy of its outage restoration communications, 2) the timeliness and accuracy of its restoration estimates, and 3) the percentage of successfully delivered outage notifications. I am providing a summary of each of these realized improvements in the pages that follow.

<u>Power Restoration Accuracy and Timeliness</u>

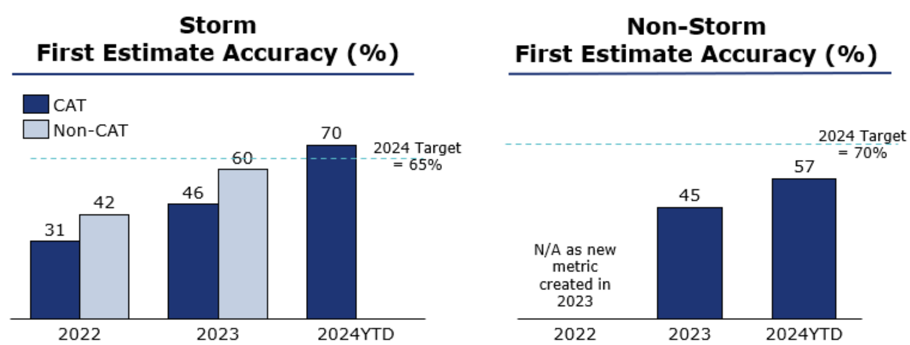
Prior to the implementation of EFC – Outage Status initiative, the customer's power status was tied to the job status, which was overall 94% accurate, but with a range between 80% to 94% during high impact and storm days. Because the power status was not premise-based, the Company could think the customer's power was restored, and communicated this status to the customer, when, in fact, the customer was not restored.

With the implementation of EFC, where the customer's power status is based on AMI meter data, the Company has consistently achieved a 99% accuracy rate for the customer's power status. However, timeliness of identifying the customer's power status could be delayed with the use of AMI data, so a new metric was developed to ensure timely delivery of power status updates – Restoration Communication within 1-hour. In 2023, 41.5% of customers who were restored received confirmation of their restoration within 1-hour, which the Company is forecasting to increase to 65% in 2024, while maintaining 99% Power Restoration Accuracy, and for which the Company has established a long-term target of 90%.

First Estimate Accuracy

One of the most significant drivers of customer dissatisfaction during an outage is the lack of an accurate restoration estimate. As such, one of the key elements of the EFC – Outage Status initiatives is to improve the timeliness and accuracy of the first Estimate Time of Restoration (ETR) that is delivered to the customers. Our leading metric, First Estimate Accuracy, measures the percent of customers that received a single and accurate estimated restoration time (ETR). The Company measures First Estimate Accuracy based on the restoration estimate information provided to our customers. In Non-Storm conditions, customers receive a day and time estimate, while in Storm conditions customers receive a day-level estimate. During a storm, an estimate is accurate if the customer receives a single estimate communication and is restored the same day as the day provided in the estimate. The Company defines First Estimate Accuracy more stringently during a Non-Storm day, as the customer must receive a single estimate and be restored no earlier than 10 minutes and no later than 3 hours of the estimate communicated. Through its EFC investments, the Company has made steady improvement in this metric, achieving the highest catastrophic storm accuracy rate to date in the January 2024 CAT storm (Figure 9).

Figure 9 - Improvement in First Estimate Accuracy



As seen in Figure 9, we have improved our first estimate accuracy between 2022 and 2023 by 48% for catastrophic storms (CAT) from 31% to 46%, and by 43% for non-catastrophic storms (Non-CAT) from 42% to 60%. Additionally, during the January 2024 CAT storm, we performed at 70%, which is above our 2024 Target of 65% for all storms. Similarly, the Company has realized improvements in estimate accuracy for Non-CAT storms, which has increased from 45% in 2023, to 57% in 2024. I would note here that because the Company changed the way we define Non-CAT estimate accuracy in 2023, there is no comparative data for 2022 performance. Long-term, the Company is targeting 95% First Estimate Accuracy during all storms, and is targeting delivery of those estimates within 4-hours of the storm weather clearing, and within 1-hour during non-storms.

Additionally, we have improved our estimate delivery timeliness—the amount of time between the weather clearing the service territory and the time outage-specific estimates are delivered to customers. Based on all process improvements, our timeliness has dramatically improved for both CAT and Non-CAT Storms. For Non-CAT storms, we are delivering estimates on average within 5.5 hours after weather has cleared, compared to 16-24 hours before the standard processes were developed. For CAT storms, we are providing estimates on average within 10 hours after the weather has cleared, as compared to 24-36 hours before the standard processes were developed.

Outage Notification Delivery

Historically, only 45% of customers with reported outages successfully received the expected outage status notifications, which includes confirmation of their outage, global restoration estimates, their personal restoration estimates, updates on the status of their outage (e.g., crew assigned, damage being assessed), and their power restored status. With its investments in EFC, the Company has increased this percentage to 70% in 2022 and 88% in 2023, and is forecasting to increase this percentage further to 92% in 2024, with a long-term target of 95%.

Q69. Can you describe what additional Core system enhancements beyond the original project scope, are being enabled by the Company's incremental investments in the EFC – Outage Status initiative?

A69. Yes. The Company has identified and is investing $5.8 million in incremental 2023-2025 capital to address emergent defects that emerged as a result of the 2023 ADMS implementation and to further enhance the PPS system, further improve restoration estimate accuracy, and to enhance outage tracking and reporting capabilities. This incremental capital is included in Exhibit A-24 Schedule N7, Page

1, Lines 1, 2, 4, 6, and 7. I describe these enhancements, and their expected outcomes and benefits, in the remainder of my response to this question.

<u>PPS Enhancements</u>

The Company is investing $2.3 million in 2023 and 2024 bridge period, and $0.3 million in 2025 test period, capital to further enhance PPS and its interfaces with the AMI system, ADMS, and WISMO. In 2023, these enhancements allowed for the implementation of system enhancements to ensure that the number of customer outages align across all systems such as the outage map, internal outage dashboards, and website outage totals. In 2024 and 2025, we are adding logic to our systems to allow the Outage Management System (in ADMS) time to process outages before we send communication to customers. This will prevent us from erroneously sending pre-mature estimate communications and/or inaccurate power status notifications. This will also help us reduce the number of power status unknown notifications. These notifications are sent when we cannot reach the customers' meters and are unable to determine whether they have power. This $2.6 million in incremental capital is included in the total Core system investments, which is reflected in the EFC Exhibit A-24 Schedule N7, on Page 1, Columns c through e, Lines 1, 2, and 4.

<u>Restoration Estimate Timeliness and Accuracy</u>

The Company is investing $1.1 million in the 2023 and 2024 bridge period, and $0.3 million in the 2025 test period, capital in its Restoration Estimate initiative, which leverages a standardization of processes and machine learning models to achieve its long-term estimate accuracy goals and objectives. This $1.4 million in incremental capital is included in the total Core system investments, which is reflected in the EFC Exhibit A-24 Schedule N7, on Page 1, Columns c through e, Line 6.

There are eight defining guiding principles (Figure 10), which have informed the creation of seven Restoration Estimate workstreams (Figure 11), two of which have been completed, that support the continuous improvement of restoration estimates to accelerate achievement of the Company’s long-term 95% First Estimate Accuracy target, and the timeliness by which estimates are communicated to customers.

Figure 10 - Restoration Estimate Guiding Principles

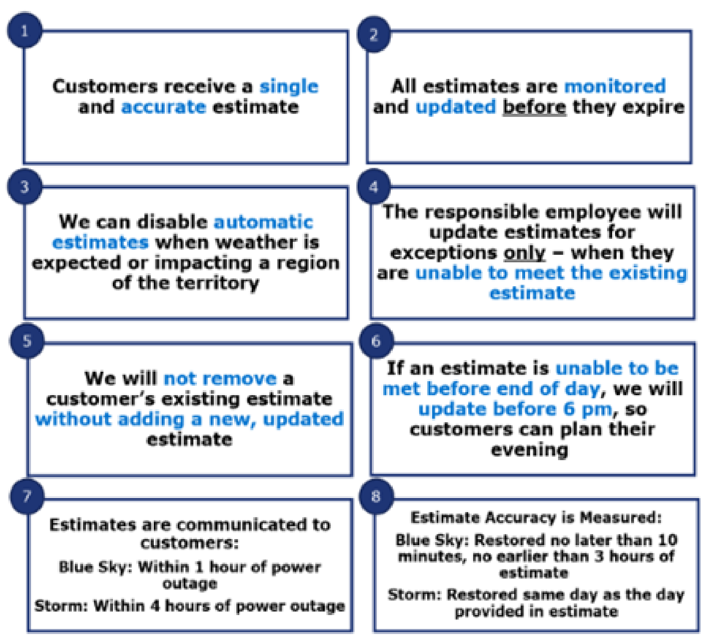
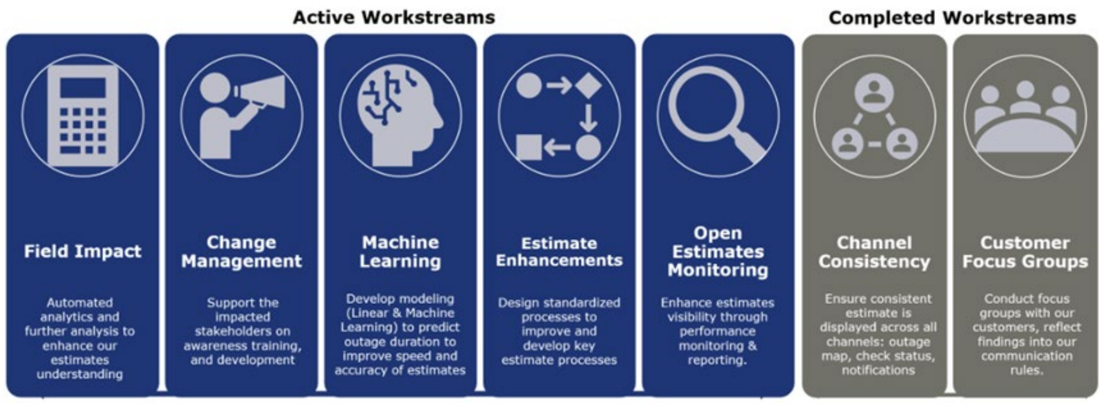


Figure 11 - Restoration Estimates Initiative - Workstreams



During non-storm outages, our outage management system generates an estimate based on an algorithm and sends it within 1 hour to our customers. And while we have improved First Estimate Accuracy significantly in 2023 (Figure 9), the continued use of a manual process during storms to generate restoration estimates means that many customers go for prolonged periods of time without an estimate, especially during CAT storms.

To reduce the amount of time required to provide customers a restoration estimate during storms, a team of data scientists has developed several versions of a restoration estimate machine learning model and are in the process of validating them against historical storm data. Once fully developed, the machine learning model will improve the timeliness of delivering storm estimates by being able to process a significant volume of historical data, such as the number of customers out, location, weather, and other environmental factors, without human intervention to generate an estimate. The chosen model will be used in the summer of 2024 to generate restoration estimates alongside our existing manual method to gauge the level of improvement and its accuracy. Once the accuracy of the model is established, we will integrate it with the outage management system. Peers with estimate models have spent several years refining their models. The model itself will require a small team of data scientists to continue to train and refine it year after year.

Outage Tracking and Reporting

The Company is investing $1.8 million in 2024 bridge period capital to enhance its outage monitoring, reporting and analytics capabilities. This incremental capital is included in the total Core system investments, which is reflected in the EFC Exhibit A-24 Schedule N7, on Page 1, Column d, Line 7.

Prior to the EFC – Outage Status initiative, we did not have one central location to monitor customer outages and the related customer experience during an outage. The systems available allowed us to monitor our job completion progress on outage restoration, but we had no way of monitoring what our customers were experiencing. For example, we did not have a robust or highly accurate method of knowing how many, and which, customers were without power, if they had received restoration estimates, and if those estimates were about to expire. Furthermore, the Company had no visibility into the status of outage notifications sent or received by our customers due to the issue of a legacy communication platform that was not able to consistently and dependably handle the high volume of communications required to be sent, nor provide an accurate record of what was the exact communication sent and make it available in all our customer channels so that customers are not provided with different information. For example, during

Line No.

several of the 2021 storms, we found there were performance problems causing the system to stop sending notifications, a situation for which the Company had no visibility of until hours later. Therefore, customers did not receive proactive information regarding their power status.

In August of 2022, the Company created new storm dashboards that allow for the monitoring of the customer experience during power outages, including real-time monitoring of the number of customers out, the number of customers restored, those without outage restoration estimates, and customers with expiring estimates. These dashboards provided the Company the visibility required during the heavy 2023 storm activity to improve the information provided to customers during both storm and non-storm outages. The dashboards also allow us to monitor the success of delivering outbound outage notifications.

Lessons learned from the use of these dashboards in 2023 informed opportunities for enhancements in 2024 that will allow the Company to be more proactive and aware during a storm, allowing it to better prioritize its restoration and communication efforts. Examples of the 2023 enhanced dashboards are in Figures 12 and 13 below.

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Figure 12 - Customer Outage Status Dashboard

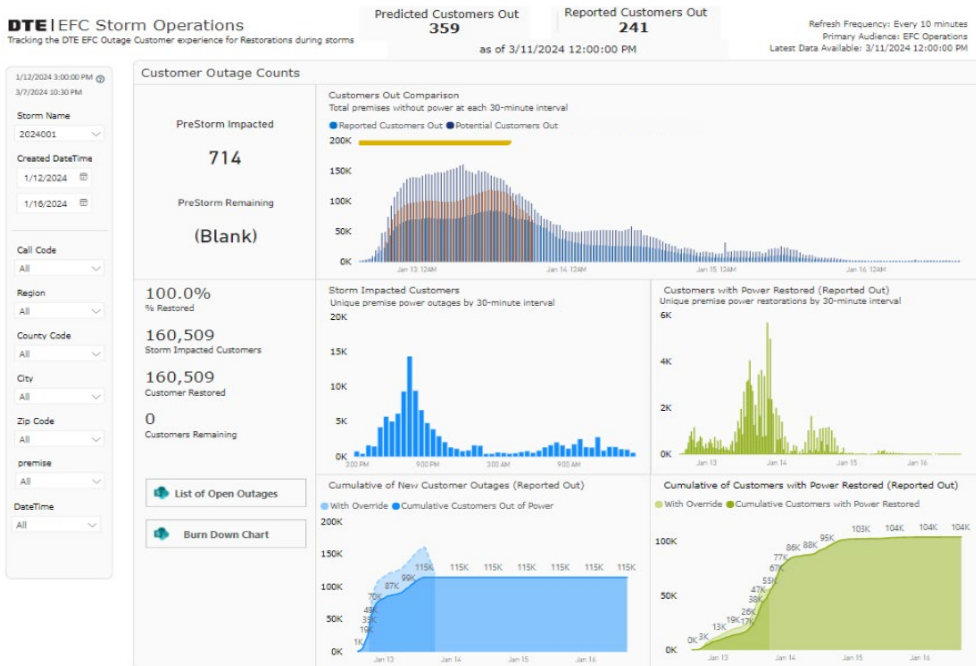
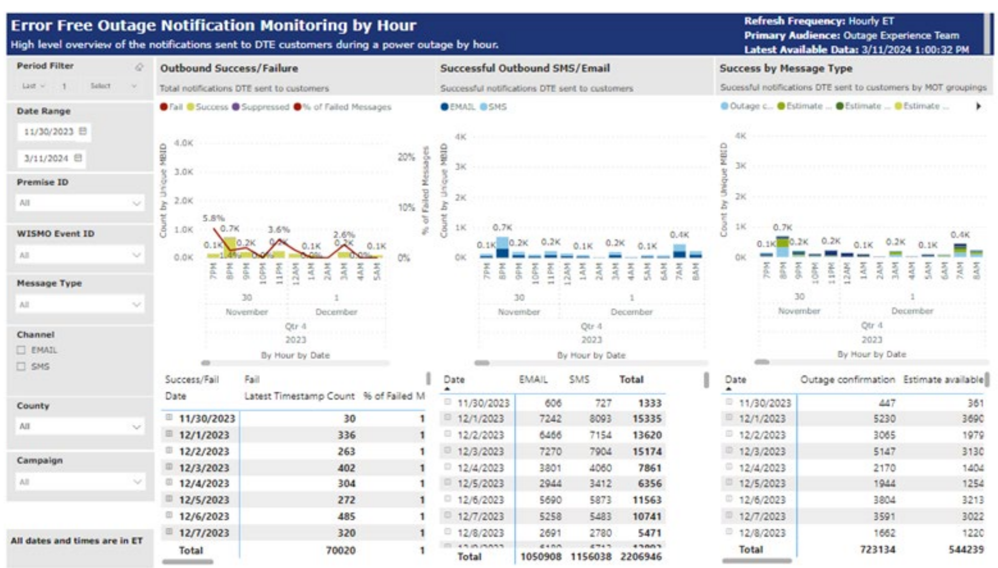


Figure 13 - Customer Outage Notifications Dashboard



The data and visibility provided by these dashboards allows Company employees to delve deeper into analyzing and understanding the impact of downstream meter issues on the effectiveness of our customer outage communications. For several reasons, such as the battery life remaining in the AMI meter before it powers down or drops in the relay of information across the meters and routers in the mesh network, the performance of AMI meters communicating a power outage within 30 minutes was at 35% in 2023, and the percent of meters with "Power Unknown" status after restoration, which relies on the PRNs successfully reaching the Company, was at 17%.

The EFC Reporting Team has been analyzing the Power Outage notifications (PONs) and Power Restoration Notifications (PRNs) from the AMI meters to identify opportunities to improve the accuracy and timeliness of the Company's outage notifications and are pursuing 2024 capital investments that will increase the percent of meters communicating within 30 minutes to 52%, and will reduce the percent of meters with Power Unknown status to 5%.

Q70. Can you describe what additional Customer-Facing system enhancements, beyond the original project scope, are being enabled by the Company's incremental investments in the EFC – Outage Status initiative?

A70. Yes. As previously described, the Company is seeking recovery for an additional $16.8 million in 2022-2024 EFC capital, beyond what was approved for recovery in U-21297, and which is inclusive of the impact of $5.2 million in 2022 EFC historical capital that was previously disallowed as part of the Commission's disallowance in U-21297 of the total $51.3 million portfolio of digital self-service

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projects. This incremental capital is included in the total amounts reflected in EFC Exhibit A-24, Schedule N7 on Pages 3-4, and which has been allocated to addressing emerging defects in the Customer-Facing systems that resulted from the 2023 ADMS implementation and to enhance the Customer-Facing systems to provide additional benefits to customers. I describe these enhancements in the remainder of my response to this question.

<u>WISMO and Outage Map</u>

The Company is investing $5.2 million in incremental 2022-2024 capital in WISMO and the Outage Map to remediate defects from the 2023 implementation of ADMS, and to fund improvements in the integration between WISMO, the Outage Map, and ADMS. Improved integration between WISMO and the Outage Map enhances the consistency of data between what is presented in customer outage notifications and what customers see on the Outage Map. This incremental spend also addressed CRM performance issues encountered during the February 2023 CAT storms, which were related to outage reporting that was migrated from CRM to WISMO, and enabling the use of WISMO to track outages reported by Police, Fire, or Municipalities, thereby providing for these stakeholders the same proactive monitoring, tracking, and messaging for these outages as for those reported by other customers. Details on costs by year for these system enhancements are in the EFC Exhibit A-24 Schedule N7 on Page 3 Lines 1-3.

<u>Notifications</u>

The Company is investing $3.0 million in incremental 2022-2024 capital to further enhance the customer outage notifications experience. In 2023, this work included:

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1) modifying the language and content for 38 outage Email, SMS, and Voice notifications as part of the transition from the prior OMS (InService) to ADMS; 2) eliminating duplicate messages; 3) ensuring proper sequencing of messages and timeliness; and 4) improving the Preference Management Center to accurately capture and use the customers' preferred service and communication channels.

This incremental investment enhances the Company's ability to proactively reach out to customers who are experiencing an outage. The details of this outreach are provided below, and for which the capital investment details by year can be found in Exhibit A-24 Schedule N7 on Page 3 Lines 4-5.

1. Notifications to Customers who are "Likely Out" – The Company uses various data points (e.g., AMI, equipment status, customer outage reports, etc.) to predict when a whole circuit or area is without power. While the new premise-based system uses customer AMI data to determine if a customer is without power, the AMI data is not available 100% of the time—such as when a meter has failed to communicate back to the Company for 100% of the impacted customers. To proactively reach out to customers who are very "likely out", the Company is developing the ability to trigger notifications to these customers to let them know that the region in which they live has been impacted by a storm, how many customers are impacted, and that it is believed that they are without power as well, and provide these customers a method (e.g., two-way texting) to confirm their power status.
2. Notifications of Planned Outage Communications – The Company is leveraging its premise-based system to improve the timeliness and quality of

customer notifications for planned outages. All our work to date has focused on unplanned outages. We still receive feedback from customers that we can do a much better job communicating planned outages.

Customer Channels

The Company is investing $3.4 million in incremental 2022-2024 bridge period capital to 1) remediate emerging CRM and digital channel defects that occurred after the 2023 launch of ADMS, 2) fund an additional $1.1 million in 2022 Outage digital self-service solution enhancements, and 3) make ongoing enhancements, including new Outage functionality and features in the Web and Mobile App.

This effort has included the continuous improvement of the Outage Map, a redesign of the native Outage App functionality, updating the Outage Center and map statistics, the customer checklist (step 2) in the report outage workflow, and the ongoing improvement in streetlight reporting, and the Police and Fire Web portal which includes enhancing the downed power line reporting form, providing additional wire types on which to report a problem, allowing Police and Fire personnel to upload photos for their reported problem, and providing Police and Fire personnel the estimated time of arrival (ETA) of DTE resources.

In 2024, the enhancements provided to Police and Fire personnel will be expanded to the Company's residential customers, first on the Web and then in the Mobile App.

Proactive “Status First” Outage communications – The Company is notifying customers that it is aware of their outage and providing those customers with relevant information. This includes messaging customers who are using a digital self-service channel to report their outage. Details on costs by year for these Channel enhancements are in the EFC Exhibit A-24 Schedule N7 on Page 3 Lines 6-8. Also, see Exhibit A-24 Schedule N10 for the completed 2022 and 2024 Outage and EFC Channel enhancements.

Part 7. Regulatory and Compliance Projects

Q71. Which Regulatory and Compliance projects will you discuss in this section of your testimony?

A71. Regulatory and Compliance investments are non-discretionary investments that must be made to satisfy MPSC requirements and other industry regulations and compliance items the Company must adhere to provide service to its customers. Part 7 of my testimony explains in detail the Company’s non-discretionary investments in the Regulatory and Compliance IT Investment Category, as shown in Lines 1 through 17 of Exhibit A-12, Schedule B5.7.3. The planned costs across the Regulatory and Compliance projects are discussed further below.

Q72. What specific projects are included in the Regulatory and Compliance IT Investment category?

A72. There are twelve projects classified as Regulatory and Compliance. Eight projects are related to Clean Energy. The remaining four projects include two that are necessary to comply with industry regulations and standards, and two projects that support the implementation of rates per approved MPSC rate case orders.

Q73. Please explain why the Company is investing in the Clean Energy projects.

A73. DTE Electric customers are becoming more aware of, and interested in, opportunities to support the growth in renewable energy and reduce or offset their carbon footprint. As such, the Company is investing in seven projects totaling $22.9 million, consisting of $1.1 million in historical period, $7.3 million in 2023-2024 bridge period, and $14.5 million in 2025 test period capital as shown in Exhibit A-12 Schedule B5.7.3, in the expansion and creation of products and services that allow customers to contribute to a cleaner environment. These investments satisfy the Company's commitments to the MPSC and our customers under the approved renewable energy plans (U-20851 and U-20713). Additionally, there is one project called MIGP Data and Reporting on Line 40 of Exhibit A-12 Schedule B5.7.3 that is categorized in the Strategic investment category that is included in this section.

Each of the MIGP tariffs have been approved by the MPSC for implementation, with the associated capital dollars reflecting the investment necessary to build the required fixed or volumetric charges in the CR&B system, to enroll or reserve customer interest in a specific MIGP program, to update the Company's MIGP Website, or to create supporting internal dashboarding and reporting to enable efficient management of the MIGP programs. I will discuss each project below that the Company is requesting for recovery in the instant case in the order in which they appear in Exhibit A-12 Schedule B5.7.3.

1. Line 4 – MIGP Customer-Requested Renewable Energy Projects

2. Line 6 – MIGP Low Income Solar Pilot
3. Line 7 – MIGP Reservation System for New Enrollments
4. Line 8 – MIGP Website Update
5. Line 10 – MIGP Large Customer Prepayment
6. Line 11 – MIGP Scope 3 Billing and Enrollment
7. Line 15 – Rider 17: MIGreenPower, Residential and Small Commercial & Industrial
8. Line 40 – MIGP Data and Reporting (Strategic Investment Category)

Q74. What is the scope of the MIGP Customer-Requested Renewable Energy Projects?

A74. The Company is investing $2.7 million in 2023-2024 bridge period, and $5.5 million in 2025 test period capital in the MIGP Customer-Requested Renewable Energy Projects. The capital requested in on Line 4 of Exhibit A-12 Schedule B5.7.3 reflects a variance of $4.6 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297 as the project has been pushed out to 2025 due to a delay in the construction of these projects.

These projects are unique contracts between a company and DTE to build dedicated renewable assets to offset the customer's electricity use with green energy. The Company has entered into agreements with two uniquely contracted customers to build two dedicated solar parks with 650 MW and 400 MW of capacity, respectively. Similar in scope to many of our MIGP renewable projects, this project will include end-to-end enhancements to the CR&B system that will include billing, reporting, accounting, and provide enrollment functionality for individual customer-requested projects, and any additional updates to fulfill the Company's commitment under these contracts. These unique contracts also require the creation and integration of a new product named "customer-requested solar park" into the CR&B system and will require enhancements and integration with SAP Business Warehouse (BW) and SAP Commerce Cloud. Customers will enroll and be billed based on the generation from these assets when the projects go into service. See Exhibit A-24 N3.1 Line 48 for additional project details.

Q75. What is the scope of the MIGP Low Income Solar Pilots project?

A75. The Company is investing $1.2 million in 2024 bridge period, and $0.8 million in 2025 test period, capital in the MIGP Low Income Solar Pilots project as shown on Line 6 of Exhibit A-12 Schedule B5.7.3. The capital requested reflects a variance of $1.0 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297 as the pilot program is taking longer than expected to launch due to funding sources. Because of this, we are not ready to enroll and bill customers for this program.

The MIGP Low-Income Solar Pilots project provides the IT functionality in the CR&B system to comprehend the Pilot's program parameters and objectives and enroll qualified low-income customers in the program. Additional functionality must also be developed in the system to collect donations that will offset the premium required for providing solar energy-sourced power to enrolled customers. This project will expand MIGP offerings to low-income customers who might not otherwise be able to participate in the program, and by enabling anyone, whether a DTE customer or not, the option to contribute into a low-income renewables fund.

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The funds from these voluntary contributions would be used in tandem with third-party donations to fully-subsidize MIGP subscriptions for low-income customers. The system capability to offer this program is addressed in the Company's Section 61 filing in MPSC Case No. U-20713, where further details of this and all MIGP programs can be found. When this project is put into service customers will enroll and be billed based on the generation from the assets. See Exhibit A-24 N3.1 Line 52 for additional project details.

Q76. What is the scope of the MIGP Reservation System for New Enrollments project?

A76. The company is investing $1.5 million in 2023 bridge period capital in the MIGP Reservation Systems project as shown on Line 7 in Exhibit A-12 Schedule B5.7.3 to allow residential and small business to enroll into a waitlist if the demand for the MIGP Program exceeds the renewable energy generation currently available. From the waitlist, customers will be enrolled into the MIGP program on a first come, first serve basis when capacity becomes available. Similar in scope to many of the MIGP renewable projects, this project will include end-to-end enhancements to the CR&B system for the waitlist functionality and any related reporting and website updates. See Exhibit A-24 Schedule N3.1 Line 53 for additional project details.

Q77. What is the purpose of the MIGP Website Update project?

A77. The Company invested $1.0 million in 2022 historical period capital in MIGP Website Update project as shown on Line 8 of Exhibit A-12 Schedule B5.7.3 which reflects a variance of $0.2 million more in the 12 months ending December 31, 2022, than was approved for cost recovery in U-21297.

The MIGP Website Update project redesigned and updated the MIGP Website and migrated it to the Cloud platform in line with the Company's cloud strategy and roadmap for all non-core processes and applications. This upgrade improves the customer experience and ease of use through a revamped process for new customer enrollments, providing existing customers with the ability to change their enrollment levels, and offering greater flexibility with guest enrollment and the customer identification process—all of which reduced the complexity of these processes. See Exhibit A-24 Schedule N3.1 Line 57 for additional project details.

Q78. What is the scope of the MIGP Large Customer Prepayment?

A78. The Company is investing $1.3 million in 2025 test period capital in the MIGP Large Customer Prepayment project as shown on Line 10 of Exhibit A-12 Schedule B5.7.3 to allow contracted customers the ability to prepay for future renewable energy charges per Section 61 of the Settlement Agreement. Development will include creating a separate renewable energy accounts receivable section on the customer's bill, a new accounting and general ledger system, and data and reporting tools to enable the program. See Exhibit A-24 Schedule N3.1 Line 50 for additional project details.

Q79. What is the purpose of MIGP Scope 3 Billing and Enrollment project?

A79. The Company is investing $3.9 million in 2025 test period capital in the MIGP Scope 3 Billing and Enrollment project, as shown on Line 11 of Exhibit A-12 Schedule B5.7.3 to allow for sponsored MIGP enrollment per the Section 61 agreement. Customers will have the ability to incur the renewable energy charges

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of another customer. For example, a business could elect to be billed for the renewable energy charges of their employees that enroll in the MIGP program. Similar in scope to many of the MIGP renewable projects, this project will include end-to-end enhancements to the CR&B system that will include the required billing, accounting, and reporting functionality. See Exhibit A-24 Schedule N3.1 Line 54 for additional project details.

Q80. What is the scope of the Rider 17 – MIGreenPower, Residential, Small Commercial, and Industrial project?

A80. The Company is investing $1.9 million in 2023-2024 bridge period and $3.0 million in 2025 test period capital in the Rider 17 – MIGreenPower, Residential, Small Commercial, and Industrial project. This capital reflects a variance of $1.9 million less in the 24 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is because the planned work could not start until after the Commission approved the project in November 2023.

This project replaces the Rider 19 MIGP Large Commercial & Industrial project, as Rider 19 ended on August 19, 2022, and has been merged with Rider 17. The project scope includes CR&B system changes required to create a fixed price offering for large customers and the ability to enroll residential and streetlighting accounts, bill customers, and other enhancements to manage and administer the program. See Exhibit A-24 Schedule N3.1 Line 80 for additional project details.

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Q81. Is the Company investing in any other projects related to supporting the management of the MIGP Programs or to integrate its renewable programs with other products and services?

A81. Yes. The Company is also investing $0.9 million in 2023 bridge period capital in the MIGP Data and Reporting project as shown on Line 40 of Exhibit A-12, Schedule B5.7.3 that will enhance the management of the MIGP programs and integrate the MIGP programs with other products and services into one reporting solution. The capital investment in this project reflects a variance of $0.7 million less in the 24 months ending December 31, 2024, than was approved for cost recovery in U-21297, because the project being rescheduled due to project reprioritization.

This solution will allow the Company to efficiently track and manage MIGP enrollments, usage data, and revenue. The current dashboard and reports rely on a manual process of exporting reports from the source system, analyzing the results, and then importing files to view in a dashboard. A more efficient solution would allow a new dashboard to be updated directly from the source system without manual intervention and in real-time. In addition, the existing manual process is becoming unsustainable as the number of MIGP enrollments continue to grow. The upward trend in the volume of data points being processed is contributing to further slowdowns in processing time.

Q82. What is the purpose of the Customer Notifications – TCPA Compliance project?

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A82. The Company is investing $0.3 million in 2024 bridge period capital for the Customer Notifications – TCPA Compliance project as shown on Line 3 of Exhibit A-12 Schedule B5.7.3 to comply with the Telephone Consumer Protection Act (TCPA), a federal regulation enacted in 1991 that was amended in 2023 to include SMS/text messages sent to a customer. The regulation includes guidelines on what constitutes a marketing communication versus necessary account communication. With our established automated notifications program, we need to enhance reporting to ensure proper monitoring of the quantities and types of notifications sent to the customer to ensure the Company's TCPA compliance. Fines for non-compliance range from $500.00 to $1,500.00 per instance. The Company sends approximately 60 million notifications annually, most of those automated messages are sent in mass to customers requiring tools to monitor these volumes. See Exhibit A-24 Schedule N3.1 Line 24 for additional project details.

Q83. What is the purpose of the PCI Compliance project?

A83. To ensure DTE Electric complies with the Payment Card Industry (PCI) Data Security Standards (DSS) established by the credit card industry and audited by a certified PCI Security Assessor.

Q84. Why does DTE need to maintain PCI compliance?

A84. In 2019, the Company achieved PCI DSS Compliance. The Company is investing $0.1 million in 2022 historical period, $0.3 million in 2022-2023 bridge period, $0.2 million in 2025 test period capital to maintain PCI DSS compliance to the most recent standards. The 2023-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3.1 Lines 66 and 69 for additional project details.

35-40% of payments received from customers are made using a credit or debit card. To accept, store, process, and transmit payments and cardholder data, DTE Electric must adhere to PCI DSS. Failure to adhere to PCI DSS could result in the loss of payment certification with our banking partners and would prevent us from being able to accept credit or debit card payments. This project ensures that DTE's Contact Center's telephony and Interactive Voice Response (IVR) systems remain PCI-compliant. Through these Contact Center systems, DTE customers can complete self-service payments over the phone's automated system as well as provide CRs with credit card information to complete their payments.

Q85. What is the purpose of the Regulatory Compliance project?

A85. The Company is investing $0.8 million in 2022 historical period, $5.6 million in 2022-2023 bridge period, and $2.8 million in 2025 test period capital, for the Regulatory Compliance project as shown on Line 14 of Exhibit A-12, Schedule B5.7.3 to fund ongoing and emerging rate changes required to be implemented in the CR&B system. The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 Schedule N3.1 Line 77 for additional project details.

This project funds CR&B and reporting system changes necessary to comply with the outcome of any MPSC rate orders, to provide funding for emerging regulatory compliance items, and to fund the implementation of new rates and programs as approved by the MPSC.

In 2022, funding from the Regulatory Compliance project supported the roll-out of the D13 rate as DTE Electric proposed a D13 XL-HLF rate to provide the Company the opportunity to optimize its load base and make incremental contributions to DTE Electric's fixed costs. The D13 rate aimed to provide customers with competitively priced electricity consistent with cost-of-service-based rates to address the changing circumstances of its automotive and other advanced manufacturing customers.

In 2023, this project, as in prior years, provides a yearly investment that allows DTE to implement IT system changes inclusive of logic and screen changes to the CR&B system for the Agency Website/Online Resource for Energy Assistance Agencies (AGW/ORA) applications, and StreamServe for bill formatting changes to support emergent Regulatory work.

As a result of a 2023 MPSC ruling, the CR&B system application revised outflow billing determinant calculation for all Rider 18 demand-based rates. The outflow demand will be determined by the average of On-Peak demand during the billing period. Also, for Rider 18 D1.8 customers, the invoice should display the Critical-Peak, Mid-Peak, On-Peak and Off-Peak information under the Current Billing Information section of the bill. Additionally, the redesign of the existing Low Income Self Sufficiency Plan (LSP) will allow for a reduced monthly plan amount developed for each household based on their previous 12-months usage while issuing monthly credit incentives based on household income and consumption. The redesigned LSP program will also change the way arrears forgiveness is issued and introduce plan amount reviews at regular intervals to ensure the customer's budget portion is aligned with their recent consumption pattern.

In the 2024 bridge period, as described by Company Witness Willis in his testimony related to the Company's proposal for transitioning D1.6 customers to the new D1.11 TOD rate and closing the D1.6 rate, investments from the Regulatory Compliance project will fund the CR&B system changes required to complete the three key elements of this transition.

Currently, the Low-Income Assistance (LIA) credit is available only to customers taking service on D1.6 – a customer who is otherwise eligible but chooses to take service on a different base rate may not avail themselves of the credit. The transition to Time-of-Day rates provides an opportunity not only to re-align rate design for D1.6 customers, but also to expand their ability to choose their base rate schedule while retaining the LIA credit. The Company anticipates the implementation of this transition will occur during the projected bridge year. Thus, the Company's Exhibit A-16, Schedules F3 and F8 both reflect the continuation of D1.6 into the 2025 projected test year given the requirement to continue utilizing the rate for a period of time.

In addition to the scope previously described, this project also ensures there is sufficient funding for planned and emergent revisions to electric rates, amendments to rate schedules and rules governing the distribution and supply of electric energy, and any other modifications of DTE Electric rates in accordance with MPSC orders.

Q86. What is the scope of the Securitization Project?

A86. The Company invested $0.3 million in 2022 historical period capital in the Securitization project as shown on Line 16 in Exhibit A-12 Schedule B5.7.3 to complete the necessary rate changes in the CR&B system to include two new securitization surcharges for residential, industrial, and commercial customers. DTE filed MPSC Case No. U-21015 requesting MPSC approval to issue securitization bonds and implement a surcharge related to the cost of the Company's retirement of the River Rouge power plant and a surge in tree trimming costs. The Commission granted approval for the securitization of up to $235.8 million in qualified costs on June 23, 2021. See Exhibit A-24 Schedule N3.1 Line 81 for additional project details.

Part 8. Historical 2022 Project Spend Variance and Other Project Variance

Q87. How much total Customer IT Portfolio capital did the Company spend in 2022, and how does it compare to what was approved for recovery in Case No. U-21297?

A87. The Company spent $224.3 million of capital on IT projects in 2022 compared to the $165.0 million approved by the Commission in Case No U-21297, as shown in Line 18 of Exhibit A-24 Schedule N2, which is $59.3 million more than was approved.

Q88. For projects supported in your testimony in the instant case, what is the variance between the capital the Company spent in 2022, and what was approved for recovery in Case No. U-21297?

A88. For the projects that I support in my testimony in the instant case, there is a variance of $21.9 million between the amount of capital that was approved for cost recovery in Case No. U-21297 and capital invested by the Company. This variance is associated with seven projects shown in Exhibit A-24 Schedule N2 and include: Error Free Communications, Bill Management, Customer Relationship and Billing Program Enhancement, Advanced Analytics Use Cases, and three projects whose spend were a sub-set of the $51.3 million Digital Self-Service Project Portfolio described in U-21297. The specific projects that make up the variance are listed below with references to the corresponding testimony in the sections above and/or in Table 9 below.

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1 **Table 9. 2022 Project Variance Explanation**

Project	Variance Testimony Reference	Variance Explanation
Error Free Communication - Outage Status	Page MJH-81, Lines 7-16.	In 2022, the Company invested $7.8 million more than was approved in U-21297 for cost recovery. The additional spend is due to $0.7 million spent on WISMO and Outage Map system enhancements to fund enhancements to the WISMO and Outage Map interfaces with the core system enhancements, $0.8 million for updating customer notifications and development of Outage status dashboard reporting, and $6.3 million on customer channel enhancements for the Web and IVR. Of the $7.8 million variance in 2022, $5.2 million funded investments to improve the customer's outage digital experience and was part of the $51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.
Journey Work Product Transformation Teams	Page MJH-21, Lines 3-5. Page MJH-25, Lines 9-11. Page MJH-29, Lines 10-12.	See testimony reference. The Company invested $6.7 million in 2022 to fund investments to improve the customer's Collections, MIMO and Outage digital experience and this spend was part of the $51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.
Bill Management	Page MJH-34, Lines 12-16.	See testimony reference. The Company invested an additional $3.4 million in the Bill Management tool in 2022 to address identified defects, to continue to enhance the Billing experience, and to incorporate the ability for the tool to effectively analyze and simulate Time-of-Day (TOD) bills, to support the TOD project go-live in March of 2023.
IVR Virtual Assistants	Page MJH-25, Table 5. Page MJH-25, Lines 19-21. Page MJH-26, Lines 1-3.	See testimony reference. The Company invested $1.3 million ($1.2 million net of 2023) in 2022 to fund investments in the MIMO Virtual Assistant to improve the customer's MIMO digital experiences and this spend was part of the $51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.

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Project	Variance Testimony Reference	Variance Explanation
Customer Relationship and Billing Program Enhancement	Page MJH-21, Lines 1-3. Page MJH-25, Lines 7-9. Page MJH-33, Lines 7-10. Page MJH-54, Lines 24-25. Page MJH-55, Lines 1-4.	The Company invested $1.2 million more in 2022 spend composed of the following two reasons: 1) $0.4 million of the 2022 CR&B spend variance is because this spend was part of the $51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297. See testimony reference. 2) The variance of $0.8 million more than was approved for recovery in U-21297 was due to additional scope required to support enhancements in the Collection, MIMO and Billing transactions to improve the customer's experience and improve First Contact Resolution (FCR). See testimony reference.
Advanced Analytics AA Use Cases Implementation	N/A	In 2022, the Company invested $1.1 million more than approved in U-21297 for cost recovery. The Advanced Analytics Use Cases project leverages advanced analytics, machine learning and other data science techniques and technologies in specific use cases to derive greater insight into customer segments, behaviors, and pain points, to understand the drivers of customer satisfaction, and to support reduction in O&M costs and uncollectible expense (UCX) or to capture operational efficiencies that improve the effectiveness of our processes and key transactions. All the 2022 variance is due to the full disallowance of the entire $4.3 million in 2022-2024 project spend in the Commission's Final Order in U-21297.
Customer Closed Loop Development	Page MJH-63, Lines 8-13.	See testimony reference. The Company invested $0.3 million in 2022 to fund investments to improve the customer's MIMO and Collection digital experience and this spend was part of the $51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.

Q89. Were there any other projects that had variances that you have not yet discussed?

A89. Yes. There are two projects listed below that were not completed in 2022 and 2023 and are not planned for completion in 2024 as previously approved for cost recovery in Case No. U-21297.

1. IVR Natural Language – This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
2. Secure Cloud Payment Provider Migration – This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.

Part 9 – Customer Service Operation and Maintenance Expense

Q90. What work does the Customer Service group perform?

A90. Customer Service is responsible for managing the customer support processes for both DTE Electric and DTE Gas. Customer Service is comprised of operational and customer strategy and insight organizations that are responsible for conducting the work associated with customer transactions, data analytics, arrears reduction, billing, and payment acceptance.

Q91. What is the role of Customer Service for DTE Electric?

A91. The Customer Service team supports the delivery of highly satisfying customer experiences and drives improvement where needed. Through continuous improvement, technology is leveraged to meet and anticipate changing customer expectations. This technology includes digital channels for customers to conduct business in the channel of choice and programs that provide added ease and convenience.

To better assist our employees in making decisions in moments of service and enable service excellence, the Company established the Keys of Service

Excellence. These keys are: Safe, Caring, Dependable, and Efficient. All Customer Service activities pass through the Service Keys. Our desired culture is one where all employees have a service mindset and a strong emotional connection to caring for our customers and each other.

Q92. What are the two divisions of Customer Service?

A92. Customer Service is made up of Operations and Customer Strategy & Insight.

Q93. What departments make up Customer Service Operations and what are their functions?

A93. Customer Service Operations consists of the following departments:

- Contact Center Operations
- Metering, Billing, & Exceptions
- Revenue Management & Protection (RM&P)
- Customer Service Operations Support

Contact Center Operations manages requests for new service, responds to inquiries regarding account information, schedules work requests from customers, and responds to emergency and trouble calls.

Metering, Billing, and Exceptions is responsible for meter reading, residential and commercial billing, major accounts billing, customer print and delivery, and bill issue resolution. The team is responsible for working and resolving any billing and collection issues that include manual intervention. These items primarily consist of billing exceptions, collections exceptions, bankruptcy, ID fraud probate, and theft work.

RM&P manages credit policies, administers low-income programs, and accounts receivable collection. RM&P is also responsible for theft investigations, remediation, and determining accountability for unauthorized usage.

Customer Service Operations Support is responsible for quality and training of Customer Service staff. It also has responsibility for the overall Continuous Improvement efforts of the Customer Service Organization.

Q94. What departments make up Customer Strategy and Insight and what are their functions?

A94. Customer Strategy and Insight consists of:

- Customer Service Transformation
- Customer Service Analytics
- Executive Consumer Affairs Center (ECAC)
- Digital Experience

The Customer Service Transformation organization provides system and technical support for the Customer Relationship & Billing (CR&B) system. The System Support group identifies emerging trends in SAP, coordinates business design, manages the translation of business needs to system design, identifies defects, and supports solutions. The Technical Support group are experts in functional design

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and serve as liaisons to the ITS organization. They conduct unit testing, complete simple configuration, support proof of concept designed, and resolve incident management tickets as applicable. The Customer Service Transformation organization also develops dashboards to visualize transaction completion and other performance metrics.

Customer Service Analytics is responsible for providing data analytics support to Customer Service, which includes data queries, reports on customer segmentation, and predictive modeling.

ECAC resolves escalated customer issues that are received from the Michigan Public Service Commission, "I Can Help" (including Media, Government Affairs, Regional Relations, and Employees), Better Business Bureau, the Attorney General, and DTE's Website. This organization also includes the Customer Insights & Research team that manages all aspects of customer satisfaction measurement and feedback loops to resolve outstanding issues from the customers surveyed. The team also collaborates with internal stakeholders to develop and execute customer-facing research such as online quantitative surveys, qualitative focus groups, and individual interviews that are used to gather customer insights.

Digital Experience is responsible for creating a customer-focused, consistent, multichannel experience that emphasizes the use of DTE's self-service channels, including mobile applications, kiosks, the DTE website, and Interactive Voice Response (IVR) to provide excellent and efficient customer service. The team has two components: (1) Transactional Experience, which focuses on customer

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transactions including policy reviews and process design to mitigate hand offs and customer dissatisfaction and (2) Digital Experience, which focuses on efficient and satisfying methods to complete these transactions.

Q95. How are costs allocated between DTE Electric and DTE Gas for Customer Service?

A95. Customer Service costs are allocated based on utility-specific data that is representative of the amount of electric- or gas- related work conducted within the organization. The allocations for the current year are based on actual activity data from the previous year. Several costs are allocated based on the number of electric and gas customers.

Call Center Operations, Customer Service Operations Support, Customer Service Transformation, Digital Experience, and ECAC expenses are allocated based on the number of electric and gas customers. For a customer who is both an electric and a gas customer, that customer is counted as one-half electric and one-half gas. For 2022, 66.2% of these expenses were allocated to DTE Electric.

Customer Billing expense is allocated between DTE Electric and DTE Gas via two cost allocation drivers. The first driver is based on the number of electric and gas customers and the second, used for Meter Reading expenses, is based on the number of Advanced Metering Infrastructure (AMI) and non-AMI customers. For 2022, 66.2% of Customer Billing expense was allocated to DTE Electric based on the number of electric and gas customers. Based on AMI and non-AMI customers, the 2022 DTE Electric allocation for Meter Reading Expenses was 9.3%

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RM&P allocates costs based on the number of accounts in arrears. For 2022, 65.2% of RM&P expense was allocated to DTE Electric.

Q96. What was the total DTE Electric O&M cost related to Customer Service for the 2022 historical test year?

A96. The total O&M cost related to Customer Service for the adjusted 2022 historical test year is $112.4 million. A detailed breakdown of the 2022 historical test year actual O&M expense adjusted by rate case eliminations, normalization adjustments, inflation, and other known and measurable adjustments is provided in Exhibit A-13, Schedule C5.7.

Q97. What expenses are included in the 2022 total O&M costs provided on Exhibit A-13, Schedule C5.7?

A97. The components that make up the $112.4 million O&M expense:

- Customer Accounts Expenses $94.7 million
- Customer Service and Informational Expenses $25.4 million
- Less Reclass to Marketing Exhibit $7.6 million

Q98. What adjustments were made to the historical test period?

A98. The following adjustments are shown on Exhibit A-13, Schedule C5.7:

- Column (c) Line 20 reflects a $7.6 million reclassification to Marketing Expenses, sponsored by Company Witness Bennett on Exhibit A-13 Schedule C5.9 Line 5.

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- Column (d) Line 19 eliminates $173 million in expenses related to the Energy Waste Reduction Program (EWR). O&M expenses for the Company's EWR program are recorded in FERC accounts 905, 907, 908 and 909. Since these costs have their own distinct recovery surcharges and are reconciled in separate MPSC proceedings, I have eliminated them from O&M. These eliminations are shown in Column (d) of Exhibit A-13, Schedule C5.7.
- Column (e) Line 19 eliminates $23.9 million for the Low-Income Energy Assistance Fund (LIEAF). The LIEAF expense being eliminated is associated with the remittance of the revenue collected through the LIEAF surcharge. Funds collected through the surcharge (a state-mandated charge) are remitted directly to the state and help provide heating assistance to low-income customers.

Q99. What are the primary activities included in the Customer Accounts Expenses category totaling $95.7 million?

A99. The Customer Accounts Expenses category includes Supervision $2.0 million, Meter Reading $2.1 million, Customer Records and Collection $76.9 million, Merchant Fees $11.8 million as supported by Company Witness Peterson, Customer 360 Amortization $2.8 million as supported by Company Witness Uzenski, and ACPP/Time of Day Reg Asset Amortization for $0.1 million.

Q100. What makes up the $2.0 million Supervision expense?

A100. Supervision expenses allocated to FERC 901 include Customer Service senior leadership and support staff.

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Q101. What activities make up the $2.1 million in Meter Reading?

A101. The Company utilizes external vendors to manually read meters not converted to AMI meters and AMI opt-out meters. These costs also include other back-office support such as route coordinators and personnel who are responsible for monitoring the adherence of the contract terms by the service provider, handling the weekly service provider billing, and analyzing meter reading complaints.

Q102. What organizations contribute to the $76.9 million of customer records and collection expenses?

A102. The organizations included in Customer Records and Collections are the following:

- Contact Center Operations
- Revenue Management & Protection (RM&P)
- Metering, Billing, and Exceptions
- Customer Experience
- Customer Service Operations Support

Q103. What activities are comprised in the Contact Center Operations organization?

A103. Much of the activity in the Contact Center Operations organization is customer-facing. Handling over four million calls annually, the organization is the front line for customer resolution. Support staff within the Contact Center Operations organization handle routing for both internal and external calls, operational support, and the telecom IVR technology associated with the Company's toll-free number.

Q104. What has been the focus of the Contact Center Operations organization?

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A104. The focus of the Contact Center Operations is streamlining the customer experience and includes:

- Incorporating CR represented web chats across MIMO and billing transactions to provide assistance to customers.
- Workforce automations that provide real-time CR productive status and schedule adherence to optimize off-phone activities.
- Continued closed-loop enhancements to provide efficient assistance to customers during a single call interaction.

These efforts are supported by projects outlined in the capital section of my testimony.

Q105. What components make up the RM&P organization?

A105. There are four major components that make up the RM&P organization:

- Internal & External Collections
- Field Operations
- Energy Advocacy Group (formerly Advocacy & Customer Offices)
- Strategy & Reporting and RM&P Staff

Q106. What are the activities of Internal and External Collections?

A106. The Internal and External Collections group uses external collection agencies to perform collection on outstanding arrears to reduce uncollectible expense. Effective use of this partnership allows the Company to mitigate the impact of

Line No.

uncollectible expense related to customers who have been disconnected. Company Witness Johnson provides more detail on uncollectible expense in her direct testimony.

Q107. What are the activities of the RM&P's Field Operations group?

A107. RM&P's Field group performs theft investigations and non-pay manual disconnects. Field Operations is responsible for driving operational efficiencies through accurate and timely shutoffs. DTE is committed to protecting the safety of our communities throughout our service territory. Effective management of energy theft minimizes lost revenue while safeguarding legitimate customers from bearing the cost of utility theft. The illegal connection activity associated with theft also exposes customers and the public in general to potential life-threatening hazards.

Q108. What activities comprise the Energy Advocacy Group (formerly Advocacy & Customer Offices)

A108. The Energy Advocacy Group (EAG) focuses on some of the Company's most vulnerable customers. This includes supporting our Low-Income Self-sufficiency Plan (LSP) customers and working with partner agencies. In 2022, the EAG team handled over 160,000 calls and completed 67,090 low-income validations and approximately 3,574 medical exception hold requests. EAG assists all customers, but with a focus on our most vulnerable. Customer Assistance Days (CADs) is one way in which assistance is provided. In 2022, the EAG team continued to assist households through virtual CADs including an In-Person DTE Customer Resource Fair hosted in partnership with THAW during its 13th Annual Week of Warmth.

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These events are often based on partnership with local agencies and organizations to provide case management solutions, energy efficiency education, and utility payment assistance to customers in need throughout the year.

Q109. What are the activities for the Strategy and Reporting RM&P staff?

A109. The Strategy and Reporting RM&P staff is responsible for creating and maintaining the customer service billing and payment plan policies. In addition, the team is responsible for compliance, supporting metrics, and data analysis as they pertain to these policies.

Q110. What are the activities of the Metering, Billing, and Exceptions group?

A110. The Metering, Billing, and Exceptions group is responsible for obtaining manual reads on DTE's meters; billing activities for residential, small commercial, large commercial and industrial customers; print and delivery for customer-facing mailings including bills; exceptions management including billing investigations, bankruptcy filings, probate filings, ID fraud and theft billing; and billing programs such as Budget Wise Bill (BWB) and eBill.

Q111. What activities make up Customer Experience?

A111. Customer Experience is responsible for developing modern technologies for customers to interact with the Company through self-service channels such as the internet and mobile applications. The self-service applications include electronic billing, payment, move ins/move outs, outage reporting, estimate communications and status updates, and others.

Q112. What work activities comprise the Customer Service Operations Support organization?

A112. Customer Service Operations Support organization has established, documented, and implemented a Quality Management System (QMS) which includes processes and procedures associated with Customer Service. Documented processes are maintained and continually improved to ensure that the QMS achieves its intended results. Over 1,000 Customer Service documented processes are included in the QMS which includes but are not limited to: Call handling, collections, digital experience, billing, and quality assurance.

QMS includes a structured quality approach to ensure processes are followed, continually improved, and operational stability is maintained. Tools used to identify risk and opportunities may include but are not limited to: Process Failure Mode Effects Analysis (PFMEA), Strengths Weaknesses Opportunities Threats (SWOT), Corrective Action Program (CAR), and Journey Mapping.

Additionally, the organization conducts training of new Customer Service employees, provides ongoing training to existing employees, and provides quality assurance for customer calls using advanced call monitoring and recording technology. These and many other key activities drive defect prevention and increase customer satisfaction. In 2021, as a result of driving continuous improvement across the Customer Service organization, DTE received the world's first ISO 9001:2015 certification awarded to a customer service organization. The certification, from the International Organization for Standardization (ISO), recognizes that the Company's employees are highly focused, motivated, and engaged in providing quality service for their customers. Customer Service will champion recertification in 2024.

Q113. What is included in the Customer Collection – Merchant Fees?

A113. Refer to Company Witness Bennett ‘s testimony in the instant case for details on merchant fees.

Q114. What are the primary components of the Customer Service and Informational Expenses category totaling $24.4 million?

A114. The Customer Service and Informational Expenses category is primarily made up of activities related to Supervision $3.8 million, Customer Assistance $15.0 million, and Miscellaneous Customer Service and Informational Expenses $5.6 million.

Q115. What is included in the $3.8 million in Supervision expenses?

A115. Most of the costs are labor for regulated marketing activities including internal and external stakeholders.

Q116. What are the primary components that comprise the $15.0 million in Customer Assistance Expenses?

A116. Excluding the Energy Waste Reduction Program and LIEAF offsets mentioned above, there are four major components that make up the $15.0 million in expense:

- Customer Service Groups
- Regulated Marketing (sponsored by Company Witness Bennet)

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- Distribution Operations
- Public Affairs

Q117. What are the activities of the Customer Service Groups (Strategy & Insight)?

A117. The Customer Service Groups drive strategy and continuous improvement processes including system and process enhancements to improve the customer experience. Activities such as benchmarking of best-in-class utilities and other world-class customer service organizations allow us to ensure we are aware of changing customer expectations and how others are responding to it. Root cause analysis activities have been critical to improving the Company's internal service, resulting in improved employee and customer engagement. The Customer Service Groups identify key customer "blue chip" priorities such as reliability, transaction excellence in the form of personalized, simple, transparent, and easy to navigate customer interactions, and contact resolution to drive the development of sustainable improvements to customer satisfaction and address performance gaps.

Q118. What activities comprise the Distribution Operations team?

A118. The activities performed by this team include issue resolution, enrollment management, and metering services including storm restoration. The team is comprised of a contact center and a team of billing analysts.

Q119. What are the activities of Public Affairs?

A119. Public Affairs identifies communities and customers in need of DTE programs and services and provides a community forum to connect low-income customers with resources and several types of energy assistance offered through the Company.

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Customers who qualify can sign up for the LSP or receive emergency relief assistance, sometimes on the spot, given agencies are on site with us at these community forums. At these forums, we also educate customers on the programs we offer, such as Home Energy Consultations and EWR assistance. In addition to these formal programs, the organization supports health and human service agencies such as United Way and Salvation Army that distribute assistance to vulnerable Michigan residents.

Our support to established community partners helps them provide facilities, volunteers, transportation, and other resources to achieve additional outreach to customers living under challenging circumstances. Many of the Company's employees advocate for customer assistance when they volunteer to support Michigan-based non-profits through the Company's enterprise-wide volunteerism program Care Force, which is run through Public Affairs.

Q120. What are the primary activities that comprise the \$5.6 million of Miscellaneous Customer Service and Informational Expenses?

A120. These activities include responsibilities of the Customer Service Transformations, Digital Experience, and Data Analytics teams. The Digital Experience department works closely with other departments across the organization to ensure that all digital touchpoints are fully integrated with DTE's business systems, providing a seamless end-to-end customer experience. Additionally, the department collaborates with external partners and vendors to implement innovative technologies and innovations to further enhance the digital experience for customers. In addition to what is mentioned above, activities include the

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implementation and sustainment of the Robotic Process Automation (RPA) team and automation in the Customer Service organization (Closed Loop activities).

Q121. What is the total amount of Customer Service O&M that DTE Electric seeks to recover in rates for the projected test period?

A121. DTE Electric seeks to recover $118.6 million (Exhibit A-13, Schedule C5.7 Column (m), Line 21) in Customer Service O&M in the projected test period. Exhibit A-13, Schedule C5.7 provides a detailed breakdown of the projected test period O&M expenses that the Company is requesting in this case.

Q122. What costs are included in the $118.6 million of O&M expense?

A122. In addition to the 2022 costs described in my testimony regarding the historical test period, the Company has included the following changes: 1) inflation adjustments in 2023 for $3.1 million, 2024 for $2.9 million, and 2025 for $3.0 million; 2) a known and measurable adjustment of merchant fees of $0.5 million supported by Witness Bennett (Line 6, Column k); 3) a reduction in Customer Records and Collection Expenses of $6.4 million (Line 5, Column k); and 4) ACPP / Time of Use Reg Asset Amortization of $3.0 million (Line 8, Column k).

Q123. How did you calculate the $9.1 million for inflation?

A123. Projected inflation for 2023, 2024, and 2025 O&M expenses was derived by applying the inflation factors supported by Company Witness Uzenski to the adjusted 2022 historical test period amounts (Column (g)).

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Q124. What represents the $6.4 million decrease in Customer Records and Collection Expenses in Column (k)?

A124. The $6.4 million decrease is the forecasted savings from expected lower call volumes enabled by Digital investments.

Q125. Can you please explain the estimated $3.0 million Customer Service regulatory asset impacts of the Company's Time of Day (TOD) Full Implementation?

A125. As explained by Company Witness Uzenski, the Company deferred certain costs related to the implementation of its Advanced Customer Pricing Pilot and Time of Day rate offering. The $3.0 million of expense represents the recovery of the deferred costs over five years. See Uzenski Exhibit A-13, Schedule C5.9.3 for the detailed calculation.

Q126. What are the Customer Service regulatory asset impacts of the Company's TOD Full Implementation?

A126. The Customer Service operational impacts of the TOU Full Implementation include resource requirements to handle an estimated incremental 430K additional calls in the Contact Center, and an additional 250K of billing exceptions. The one-time $5.2 million incremental costs in Customer Service related to these initiatives are shown on Exhibit A-13, Schedule C5.9.2, Line 11. The Customer Service IT related costs of $2.5 million are shown on Exhibit A-13, Schedule C5.9.2, Line 9.

Q127. Does this complete your direct testimony?

A127. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

BRIAN L. HILL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF BRIAN L. HILL

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Brian L. Hill (he, his, him), and my business address is One Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Michigan State University Eli Broad College of Business. I graduated with a Bachelor of Arts Degree in Materials & Logistics Management with a focus on Operations Management. I received a Juris Doctorate (JD) Degree from the University of Detroit Mercy School of Law. I have also completed several Company sponsored courses and attended various seminars to further my professional development, including Lean Six Sigma Certification.

Q4. Please summarize your professional experience.

A4. I began my career in the automotive industry working for Johnson Controls; a world-wide Tier 1 OEM supplier. I worked there from 1994-2008 where I held a series of positions in materials, operations, and plant management. In my plant manager role, I was responsible for all aspects of the business including safety, operations, engineering, quality, materials, finance/accounting, continuous improvement, and human resources. The plant employed approximately 400 people comprised of both salaried employees and UAW union members. My employment with DTE began in October 2008 as the Logistics Manager in Energy

Supply. Between January 2011 and November 2012, I was the Senior Supply Chain Manager at the Fermi 2 Nuclear Power Station where I held responsibility for warehousing, procurement, contracts, and work management. These activities were essential to supporting safe, reliable, and efficient plant operations, including refueling outages. Between December 2012 and March 2015, I was a Director in Corporate Services where I held increasing leadership responsibility in the Center of Excellence, Supplier Performance Management, and Facilities Operations. In this role I was responsible for strategic planning, operational metric reporting, safety strategy, resource planning, financial forecasting, and continuous improvement. I was also responsible for the long-term and daily operations of facilities management, including asset management. Between April 2015 and October 2016, I was the Director of Tree Trimming in the Distribution Operations organization of DTE Electric. In this role I was responsible for leading the strategic development and implementation of the Enhanced Tree Trim Program. In addition, I was responsible for Tree Trim Operations, comprised of DTE Energy employees and tree trim contractors (comprising over 500 employees in 2016). In this role, I was responsible for safety, quality, productivity, customer satisfaction, storm and trouble restoration efforts, and relationships with municipalities. In November 2016, I started my current role as the Director of Scheduling and Coordination in the Distribution Operations organization of DTE Electric. During this time, I was also responsible for the Project Management Office from November 2016 until June 2022 where I managed a large portfolio of projects and programs for Distribution Operations that included planning and construction. In October 2023, I was assigned the Director position for Southwest Regional Customer Operations and Scheduling & Coordination.

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Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. Yes. I am a Licensed Attorney in the State of Michigan and a Lean Six Sigma Black Belt.

Q6. What are your current duties and responsibilities?

A6. My responsibilities as Director Southwest Regional Customer Operations and Scheduling & Coordination include six primary areas: 1) Southwest Regional Customer Operations, 2) Overhead & Underground Scheduling, 3) Substations Planning & Scheduling, 4) Work Management, 5) Billing, Unitization, and Inspection, and 6) Safety, Human Performance, and Hazardous Energy Control. These organizations are briefly described below:

Southwest Regional Customer Operations: Lead over 800 full-time and contract employees responsible for engineering, planning, maintaining, operating, constructing, and improving the electrical system to ensure the delivery of safe, reliable electric service. The Southwest region has three service centers located in Newport, Belleville, and Ann Arbor that serve approximately 605,000 customers.

Overhead & Underground Scheduling: This organization schedules all planned work for both DTE and contractor field crews on overhead and underground sub transmission and distribution assets.

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Substations Planning & Scheduling: This organization plans and schedules all work for both DTE and contractor field crews on substations assets. The team also includes field contractor oversight for substation construction and modifications.

Work Management: This organization leads systematic approaches to track and measure work as well as streamline both business processes and routine tasks. The team governs the Maximo Business Process that coordinates team collaboration and workflows across all levels of the organization.

Billing, Unitization, and Inspection: This team is responsible for contractor accounts payable & invoicing, unitization of capital investments, and conducting field quality inspections to validate construction is built to standards and specifications.

Safety, Human Performance, and Hazardous Energy Control: This team includes subject matter experts (SMEs) in the areas of electrical safety, human performance, and hazardous energy control (red tag/lock out tag out). The SMEs are responsible for procedures, training, and governance of these safety programs.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in Case No. U-21297. In addition, I supported witness testimony related to the enhanced tree trimming program in prior rate cases.

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. My testimony supports, as reasonable and necessary, the historical capital expenditures and proposed capital expenditures related to base capital programs (emergent replacements, customer connections, relocations, and others). My testimony also provides an explanation of the Company's purchase and use of Portable Generators (included in Exhibit A-12, Schedule B5.4, page 13, line 28 under Infrastructure Resilience and Hardening Pillar) and an update on Miss Dig (which is not a capital program or expenditure) reporting changes made since Case No. U-21297.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plant (Pages 1-8 & 13-22)
A-23	M4	Distribution Plant Capital Project Detail – Base Capital

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following four parts:

Part I Emergent Replacements

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Part II	Customer Connections, Relocations & Other
Part III	Portable Generators
Part IV	Miss Dig

<u>Parts I & II: Base Capital Programs</u>

Q12. Can you please summarize what is included in Distribution Operations Base Capital Programs?

A12. Capital investments in base capital programs are summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, including Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 8 for Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4 for base capital programs are AFUDC on page 19 and plant activity starting on page 20. Base capital programs are further supported on Exhibit A-23, Schedule M4.

Part I: Emergent Replacements

Emergent Replacements – Storm

Q13. Generally, what is included in Emergent Replacement – Storm?

A13. This category includes investments required to restore the overhead and underground distribution systems, the sub-transmission system, and substations from damage and outages occurring during weather events called "storms." A storm is defined as greater than 760 customer outage events (an outage event is when customers are left without power) impacting greater than 200 circuits. These investments are necessary and prudent to restore customers' power by replacing damaged equipment that caused customer outages and/or public hazards. Examples of equipment that are typically replaced in a storm include poles, crossarms, and conductors, which are most often damaged by weather and tree impacts. When poles and power lines break, they can result in customer power outages and wire downs that create potential public safety hazards.

Q14. What is the Emergent Replacement – Storm expenditure forecast for 2023 through 2025?

A14. At the time the 2023 storm expenditures were estimated for use in the instant case, prior to the end of 2023[1], the Company forecasts the 2023 Emergent Replacement – Storm expenditures to be $282 million (Exhibit A-12 Schedule B5.4, page 1, line 3, column (c)). This forecast is higher than the 5-year historic inflation adjusted average of $230 million for the time-period 2018 through 2022 (Exhibit A-12 Schedule B5.4, page 3, line 5, column (g)). The 2023 storm expenditures were higher than the 5-year average because the company and our customers experienced

[1] Unless otherwise noted, in this testimony 2023 forecasts are based on eleven months of actuals (January through November) with December being an estimate.

significant storm events in 2023. 2023 included five catastrophic storms, including the most damaging winter ice storm in Company history, and another summer catastrophic storm event that included heavy damage from historic six tornadoes. Storm expenditures for 2024 and 2025 are forecasted at $244 million and $251 million, Exhibit A-12 Schedule B5.4, page 2, line 3, columns (f) and (g), respectively, based on a 5-year inflation adjusted historic average of the period 2018-2022.

Q15. Why is the Company forecasting 2024 and 2025 Storm expenditures using a 5-year inflation adjusted historic average?

A15. DTEE is using a 5-year inflation adjusted historic average to forecast 2024 and 2025 because this method is consistent with Commission Orders in the Company's previous rate cases, specifically Case Nos. U-20162, U-20561, Case No. U-20836, and Case No. U-21297. The Company agrees with the Commission that this method smooths out the variable impact of storms from year-to-year.

Q16. How is the Company reflecting the impacts of the actions it is taking to offset inflationary pressures in the emergent category?

A16. The Company is offsetting inflationary expenditures in emergent investments based on strategic capital investments and the Tree Trim (TT) Surge program. This offset is shown in Exhibit A-12 Schedule B5.4, page 2, line 6 and is $21 million for Calendar Year (CY) 2024 and $21 million for CY 2025. These avoided expenditures are calculated using the Company's reliability model as discussed by Company Witness Kryscynski.

Q17. Are there any investments planned by DTEE Information Technology (IT) that support the Company's storm processes?

A17. Yes, there are three DTEE IT investments that support the Company's storm processes. These investments are the Storm Data Lakehouse, the Storm Simulation Lab, and the Storm Cloud. All associated investments and benefits for these projects can be found in Exhibit A-12 Schedule B5.7.4 and B5.7.7 which are sponsored by Company Witness Sharma.

<u>Catastrophic Storms of 2023</u>

Q18. Can you describe the number and nature of the storms that impacted the Company's service territory in 2023?

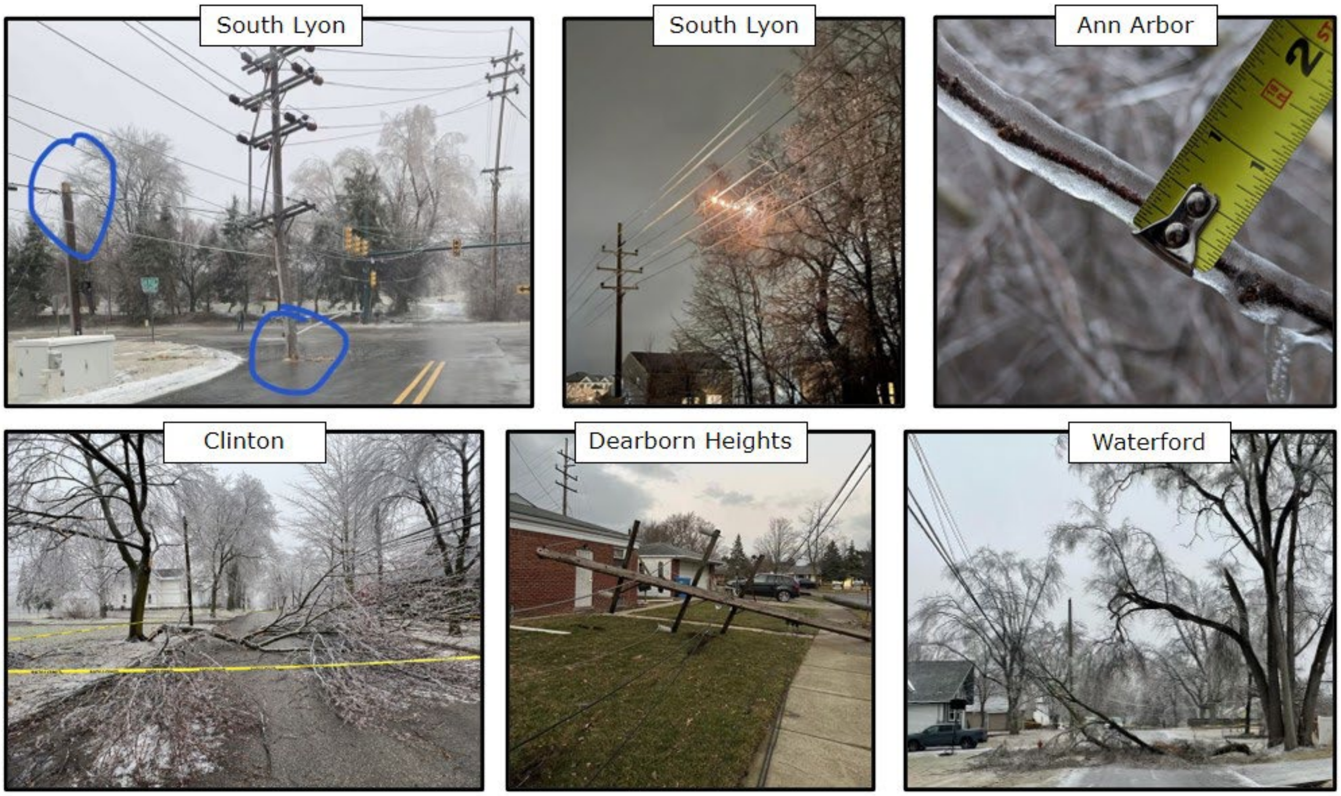
A18. Between January and August of 2023, the Company experienced seven storm events. Driving investment expenditures in the emergent category, five of these seven storms events (71%) were Catastrophic (CAT) in nature and amongst the most damaging in Company history. The frequency and intensity of these CAT storms resulted in a frustrating year of outages for our customers, and a significant amount of storm restoration work for the Company.

The seven storm events included two level 1 catastrophic CAT-1 storms and three level 2 catastrophic CAT-2 storms. A CAT-1 storm is defined as 110,000 customers or more without power in a 24-hour period (5% of total customers affected). A CAT-2 storm is defined as 220,000 customers or more without power in a 24-hour period (10% of total customers affected). The largest of these storms occurred on February 22nd, 2023 and left more than 675,000 of the Company's customers without power. Due to the extensive damage caused by the February ice storm, combined with the intensity and the frequency between the four summer CAT storms, all storm damage could not be fully repaired before the next extreme weather event hit our service territory. This left the electrical system in an abnormal condition with many temporary repairs that made it more susceptible to damage in subsequent storms.

Q19. Can you provide more detail on the February 2023 Ice Storm?

A19. On February 22nd, 2023, an ice storm struck Michigan, causing widespread power outages and hazardous conditions. The freezing rain and ice that hit Michigan downed trees and limbs, power lines, and cut power to about 700,000 homes and businesses, closed schools and offices, and delayed air travel. This was the most damaging ice storm in the Company's history, leaving 675,000 DTE customers without power, some for extended periods of time. The ice was almost ¾" thick in many areas and the weight of the ice severely damaged trees, wires, equipment, and poles. The ice storm also produced heavy wind gusts. The ice and wind caused more than 14,000 reported downed wires across our service territory. Downed trees (roads/streets were closed) and hazardous road conditions presented restoration challenges for our crews.

Figure 1 February 22, 2023 Storm Damage



Q20. Can you provide more details on the August 2023 storm that included a historic six tornadoes in the DTEE service territory?

A20. On August 23rd, 2023, seven tornadoes touched down in Michigan during late-night thunderstorms that rapidly swept across the lower half of the state. This storm set a Michigan record for the most single-day number of tornadoes in August. Six of these tornadoes touched down in southeast Michigan and in the Company's service territory, resulting in over 390,000 customers without power, some for extended periods of time. The tornadoes uprooted large trees causing extensive damage to pole and wires in several areas across our service territory. This weather event included over 4,600 reported wire downs.

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Figure 2 August 23, 2023 Storm Tornadoes

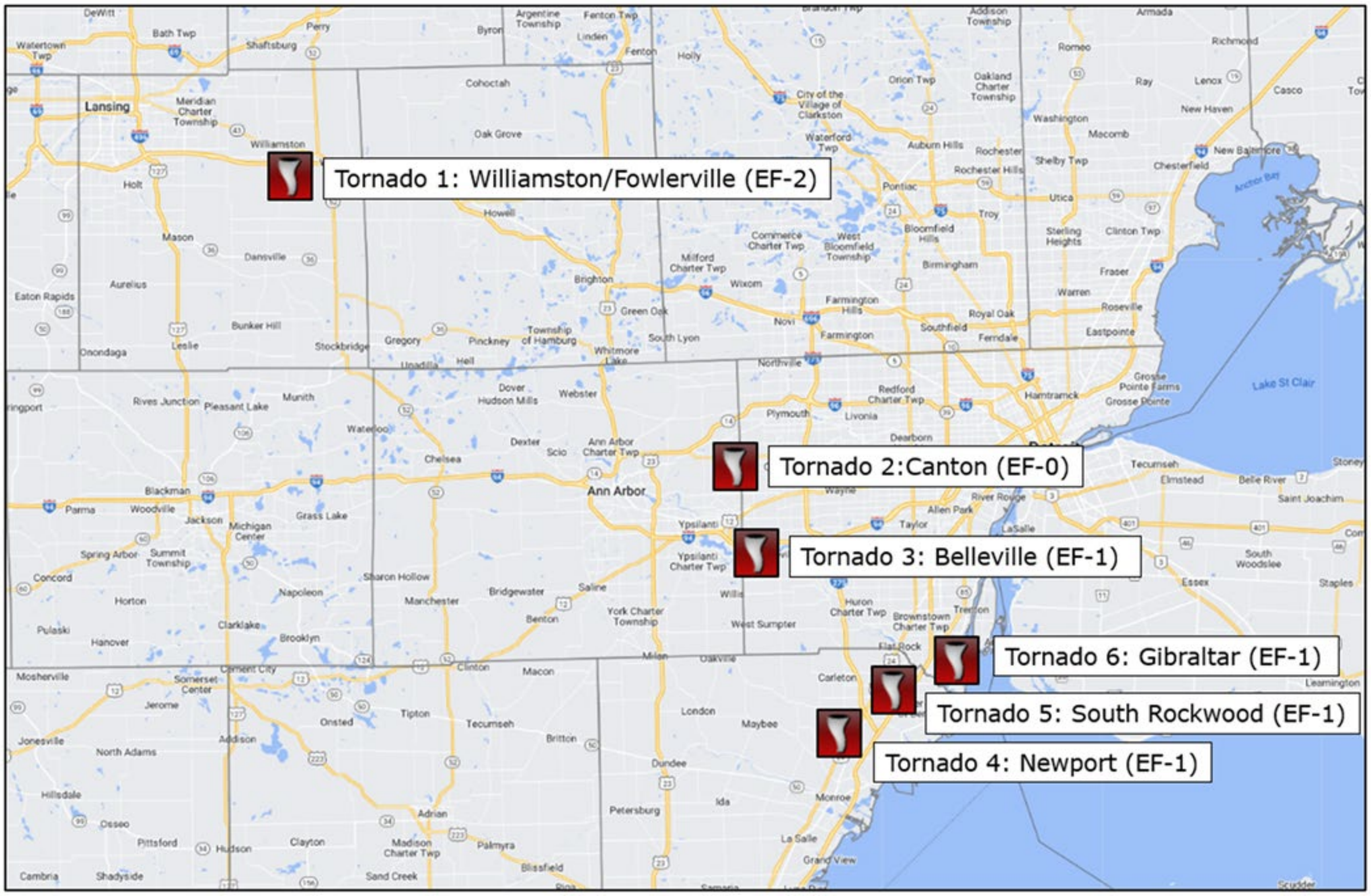

Figure 3 August 23, 2023 Storm Damage

Figure 4 August 23, 2023 Storm Damage

<u>Emergent Replacement – Non-Storm</u>

Q21. Generally, what is included in Emergent Replacement – Non-Storm?

A21. This category includes capital replacements required to return the overhead and underground distribution systems, and subtransmission electrical system to restore power and/or return to normal operating configuration during non-storm conditions. Non-storm conditions are defined as fewer than 760 customer outage events for the entire system. It includes overhead & underground distribution and the subtransmission system during non-storm conditions, but does not include planned strategic replacements. The "non-storm" description does not imply that these events are not caused by storms, high winds, or other weather-related events. It simply means that there were not enough customer outages for the "storm" threshold to be declared within a twenty-four-hour timeframe. Severe weather damage degrades the electrical system and subsequently results in emergent failures that would then be considered non-storm emergent. This category also includes equipment that fails for other reasons, not related to weather. Not all equipment failures lead to outages. However, failed and damaged equipment are considered emergent and the need to replace this equipment is reasonable and prudent, because it poses risk of power outages and hazards. Examples of this type of work include the replacement of a failed system cable or a broken insulator that has caused a floating line which could break and create an outage or wire down. In addition to trees, some of the non-storm causes for equipment failure include age, overloading, electrical or mechanical issues, vehicles striking poles, or animal interference. Table 1 provides the four high-level non-storm categories, brief descriptions, and examples.

Table 1. Emergent – Non-Storm Description

Category	Description	Example
Non-Storm Emergent	Emergency replacements of equipment during period outside of a declared storm, when customers experience issues with their power supply under both outage and non-outage conditions, but when number of outages is below the Storm threshold	**7/7/2022 Dearborn Heights** • Garbage truck hopper contacted a communications line and ripped down 5 spans of primary wire and also broke 4 poles and cross arms • Crew cleared the hazards, restored most customers, replaced wires and poles, and then restored remaining customers
Non-Storm Reactive	Replacements of equipment that does not need immediate action and can be scheduled. This includes replacement of failed devices that can be perform during follow-up work that is required to finalize the replacements of assets after initial work is completed to restore customer power and address immediate safety concerns	**4/13/2022, Detroit** • Broken pole reported due to vehicle accident; crew temporarily fixed pole to remove hazard • Pole was replaced on 5/14/2022; this follow-up work was classified as "Non-Storm Reactive"
Non-Storm Corrective	Replacements of equipment that are required to restore system to original configuration and involve coordination from the System Operations Center (SOC)	**1/23/2022, Southfield** • Failed underground cable caused an outage that a crew restored, but left system in abnormal condition • Planned outage took place 1/27/2022 and 1/28/2022 to replace the damaged cable; this work was categorized as "Non-Storm Corrective"
Non-Storm Environmental	The disposal of environmentally hazardous materials from the Company's retirement units/assets that are replaced outside of a declared Storm	**3/13/2022, Detroit** • Car hit pad mounted transformer, damaging it and causing an oil leak • Crew removed transformer and replaced it • Environmental crew cleaned up oil

Q22. What is the Non-Storm forecast for 2023 through 2025?

A22. At the time the 2023 non-storm actual expenditures were estimated for use in the instant case, prior to the end of 2023, the Company forecasted expenditures to be $207 million (Exhibit A-12 Schedule B5.4, page 1, line 4, column (c)). This forecast is the same as the 5-year historic inflation adjusted average of $207 million for the time-period 2018 through 2022, Exhibit A-12 Schedule B5.4, page 3, line 12, column g. The drivers behind increase non-storm emergent expenditures were discussed in detail in Case No. U-21297 T5 2745-2750. This included supply chain disruptions, inflation, increasing frequency and severity of weather, greater emphasis on replacing aged and outdated equipment rather than repair, a shift to higher specification materials and components (e.g., fiberglass crossarms rather than wooden), an increase in significant events that require more field crew resources to remediate, a storm preparation strategy to call in crews earlier in anticipation of storm events, and an increase use of contract and out-of-state field crews to be able to more quickly respond to storm events and eliminate follow-up work backlogs immediately after storms. Non-storm emergent expenditures for 2024 and 2025 are forecasted at $220 million and $227 million (Exhibit A-12 Schedule B5.4, page 2, line 4, columns f and g) based on a 5-year inflation adjusted historic average of the period 2018-2022.

Q23. Why is the Company forecasting 2024 and 2025 non-storm expenditures using a 5-year inflation adjusted historic average?

A23. The Company is using a 5-year inflation adjusted historic average to forecast 2024 and 2025 because this method is consistent with Commission orders in previous Case Nos. U-20162, U-20561, U-20836, and most recently, Case No. U-21297 dated December 1, 2023. The Company agrees with the Commission that this method is appropriate to account for year-to-year weather variations.

Q24. Would it be reasonable or prudent to defer Emergent Replacement – Storm & Non-Storm?

A24. No. This work is reasonable and prudent because it addresses system hazards, including customers without power or having partial power. Deferring this work would leave customers without power, reduces grid resiliency, poses system risk of additional equipment damage resulting in further customer outages, and leaves critical equipment in abnormal conditions. A learning from prior storms was that faster response to address abnormal circuits and equipment as much as reasonably possible before the next weather pattern impacts our service territory mitigates risk for larger customer outages.

<u>Emergent Replacement - Substation Reactive</u>

Q25. Generally, what does Emergent Replacement – Substation Reactive include?

A25. This category includes investments required to perform emergency replacements for substation equipment. The Company makes these investments to replace broken equipment that either led to customer outages, created risk of customer outages, or impacted the operability of the electrical system. Table 2 provides the high-level substation reactive categories, a brief description, and an example.

Table 2. Emergent – Substation Reactive Description

Category	Description	Example
Substation Reactive- Major Equipment	Replacement of the Company's substation equipment classified as major equipment	**August 2022, Twelve Mile Substation** • Fire led to catastrophic failure and complete loss of substation • Company deployed portable equipment including a substation and multiple generators
Substation Reactive – Minor Equipment	Replacement of the Company's substation equipment classified as minor equipment	**April 2022 UNVIL Substation** • 40kV insulator broke free • Replaced three 40kV insulators
Substation Reactive – Transformers and Regulators	Replacement of substation transformers and regulators	**October 2022, Middlebelt Transformer 2** • 40-year old transformer failed internally causing outages • Load switched to another transformer for two days until change of transformer complete
Substation Reactive – Non-Electrical Equipment	Replacement of substation retirement units/assets not directly related to generation or transmission of electricity	• Control house HVAC heating to remove condensation which can erode equipment • Fence/gate repairs which are mandated by NERC

Q26. What is the Substation Reactive investment forecast for 2023 through 2025?

A26. At the time the 2023 expenditures used for the instant case were estimated, prior to the end of 2023, the Company forecasted expenditures to be $42 million (Exhibit A-12 Schedule B5.4, page 2, line 5, column (e)). This forecast is lower than the 5-year historic inflation adjusted average of $46 million for the time-period 2018 through 2022 (Exhibit A-12 Schedule B5.4, page 3, line 19, column (g)). Substation Reactive expenditures for 2024 and 2025 are forecasted at $49 million and $51 million (Exhibit A-12 Schedule B5.4, page 2, line 5, columns (f) and (g)), respectively, based on a 5-year inflation adjusted historic average of the period 2018-2022.

Q27. Why are non-electrical substation equipment failures classified under substation reactive expenditures?

A27. They are classified this way because the assets and equipment are critical for safety, reliability, and security of the distribution grid. For example, substation fencing prevents the public from entering energized high voltage areas, protects critical equipment, and is part of the grid security plan. When fencing and other physical security type devices fail in an emergent manner, they need to be replaced quickly to ensure public safety and protect the security of the grid. Other equipment like HVAC systems control temperature and condensation in the substation. If this equipment fails, it must be immediately replaced to ensure that the substation operates as designed. Another example of non-electrical substation equipment is substation building infrastructure that houses equipment that fails and must be replaced (roof, doors, sidewalks). These activities are truly reactive in nature and require the Company to take immediate, prudent action to protect the safety, reliability, and security of the electrical system.

Q28. Would it be reasonable or prudent to defer Emergent Replacement – Substation Reactive?

A28. No. This work is to replace critical electrical grid equipment that has failed. Substation equipment tends to be less impacted by storms and other weather events, however, when substation equipment fails, in many cases it leaves thousands of customers without power for what can be extended periods of time. The failed equipment significantly reduces distribution capacity and redundancy that is necessary to serve customers in the event of additional system failures and increased seasonal loads. Both these conditions increase risk of additional customer outages. Substation capacity and redundancy is critical and required because these types of failures generally result in repairs that are very lengthy in time (weeks or months) which could result in extended customer outages.

Q29. Can you provide additional details regarding Emergent Capital categories for all storm, non-storm, and substation reactive expenditures?

A29. Yes. Categories of storm, non-storm, and substation reactive, along with descriptions and examples, are provided in Tables 1-3. Expenditures in Storm and Non-Storm Emergent are incurred in support of the field activities under eight work type categories: Emergency Job, Critical Infrastructure, Customer, Hazards, Multiple Customer Outage, Police/Fire, Public Safety Concern, Single Customer Outage, and Single Customer Problem. Table 3 provides examples for each category.

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Table 3. Storm and Non-Storm Work Category

Category	Description
Emergency Job	Non-outage events of the highest priority. These events are restricted to situations where the health and safety of a person are at imminent risk such as a person contacting the Company's electrical equipment, being trapped in a vehicle, building, or elevator due to power failure, downed wires, broken poles, etc.
Critical Infrastructure Customer	Outages affecting hospitals, schools, water and wastewater systems, or other critical infrastructure
Hazards	Non-outage events reported by customers to alert the Company of a potentially hazardous situation due to a sparking wire, broken pole, pole-top fire, and/or a tree or branch resting on a wire
Multiple Customer Outages	Outage events affecting more than one customer on a circuit. Events are created by the Outage Management System (OMS) prediction engine, which uses customer calls, AMI meter data, and the Company's network model to determine the size and extent of an outage. These outages can be caused by weather, trees, animals. public interference (e.g. vehicle accidents), and equipment failures and can involve concerted restoration efforts from overhead, underground, and substation personnel to restore power
Police/Fire	Non-outage events reported by a police or fire department. These events are created when police or fire personnel use their unique PIN number through one of the Company's reporting channels to report an event such as downed power line on a structure or a fire
Public Safety Concern	Non-outage events reported by customers where a primary or secondary wire is believed to have fallen and may pose a safety risk
Single Customer Outage	Outage events that affect a single customer through the same inputs as a multiple customer outage
Single Customer Problem	Non-outage events affecting a single customer that are not outages but can include power quality issues, such as low voltage or flickering lights, or downed service drops where a customer still has power

Q30. Has the Company begun to track and report Substation Reactive imminent failure work in accordance with the Order in Case No. U-20836 on November 18, 2022?

A30. Yes. The Company modified its accounting system to begin to track these expenditures and retrained its workforce to be able to separate expenditures related to imminent failures.

The Company first began collecting Substation Reactive expenditures associated with imminent failures in January 2023. Imminent Failure Substation Reactive categories are shown in Table 4.

Table 4. Substation Reactive – Imminent Failure Detail[2]

Substation Reactive	2023 ($ thousands)
Imminent Failure – Major Equipment	$15.9
Imminent Failure – Minor Equipment	$587.7
Imminent Failure – Minor System/Circuits	$605.1
Imminent Failure – Transformers/Regulators	$10.0
Failures – Major Equipment	$11,075.9
Failures – Minor Equipment	$13,321.9
Failures – Minor System/Circuits	$17.5
Failures – Transformers/Regulators	$11,158.6
Failures – Non-Electrical	$4,385.6
Total Substation Reactive	**$41,178.3**

Part II Customer Connections, Relocations & Other Capital Investments

Q31. Can you please describe the Company's Customer Connections, Relocations & Other Capital Investments?

A31. The customer connections, relocations, and other investments category is broken down into six major subcategories: (1) Customer Connections and New Load; (2) Relocations; (3) Electric System Equipment; (4) Normal Retirement Unit Change-out (NRUC) and Improvement Blankets; (5) General Plant, Tools & Equipment

[2] Values in this table are 2023 calendar year actuals (January through December).

and Miscellaneous; and (6) Public Lighting Department Project. These six subcategories are discussed in more detail below.

Q32. Why is the Company forecasting 2024 and 2025 Customer Connections, Relocations & Other Capital Investments using a 3-year inflation adjusted historic average?

A32. DTEE is using a 3-year inflation adjusted historic average to forecast 2024 and 2025 for this category of expenditures because it believes this method is consistent with the Commission Order in the Company's previous rate case, Case No. U-21297.

There are two exceptions in this category of expenditures that do not use a 3-year inflation adjusted average because they are discrete projects for I-375 relocations and Incremental Infrastructure for EV.

Q33. What capital expenditures fall into the Customer Connections and New Load subcategory?

A33. Connections and New Load expenditures include: (1) Small Load Growth Projects (2) Customer Connections, (3) New Business Projects, and (4) Incremental Infrastructure for EV.

Small Load Growth Projects and Customer Connections both include projects required to serve new load, perform upgrades necessary to address small loading issues, and connect customers to the electrical system. Activities in these projects may include reconductoring lines, expanding a substation, or transferring load to provide local capacity. The Company may also install additional overhead and/or underground lines to provide service to small commercial businesses or housing developments. Small Load Growth & Customer Connections projects typically require less than $500,000 of expenditures to complete, are less complex in nature, and are therefore developed and executed locally by regional distribution service centers. Small Load Growth & Customer Connections projects are often requested by customers and can include a customer contribution in aid of construction (CIAC) component wherein the customer pays an allocated cost of the new service depending on the load requested and service requirements.

Like Small Load Growth & Customer Connections projects, New Business projects are also required to serve new load, connect customers to the electrical system, or address local loading issues, however, they are larger scale projects. These larger customer-driven projects typically require more than $500,000 of expenditures and require a more extensively engineered design to connect customers to the electrical system. New Business projects are typically requested by customers and can also carry a CIAC component.

Incremental Infrastructure for EV (electric vehicles) is incremental capital for construction of EV charging infrastructure and is a subset of the Company's Transportation Electrification Plan (TEP) discussed further in Question 41 of my testimony.

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Q34. What capital expenditures fall into the Relocation subcategory?

A34. Relocation projects are requests from customers, cities, municipalities, or other governmental entities, for example, the Michigan Department of Transportation (MDOT). These are requests to relocate existing Company equipment and facilities. These requests are typically related to construction related to the modification of roadways, bridges, water mains, public sanitation, alleys, or other customer activities.

The Company equipment being relocated could include overhead lines and poles, underground lines and transformers, and substations equipment. With the increases in federal funding levels for investments in replacing and building infrastructure, it is expected that these types of projects will become more frequent.

These investments enable economic growth, meet customer needs, are required by regulation, or in some cases are constructed at the request or mandate of governmental entities. Like Customer Connections and New Business, some projects in this category can carry a CIAC component.

Q35. What is the I-375 Relocations project under Major Infrastructure Relocation Project in this instant case?

A35. MDOT has notified DTEE that the Company will need to relocate distribution infrastructure currently located in the I-375 below-grade freeway corridor, which will be replaced with a grade-level boulevard. MDOT construction is expected to begin in 2025, with DTEE work starting in 2023. This project captures the Company's initial support for the MDOT's I-375 Reconnecting Communities

Project. The Company's support for this project is estimated to require an expenditure of $39 million (Exhibit A-12, Schedule B5.4, page 5 line 37) spanning from 2023-2025, with the majority of the required work being performed in 2024.

Q36. What capital expenditures fall into the Electric System Equipment subcategory?

A36. The Company maintains an inventory of critical spare equipment to support emergent replacements and planned projects. This allows equipment repairs and replacements to proceed expeditiously, without waiting for parts delivery from vendors. Equipment purchased under this subcategory includes substation transformers, distribution transformers, regulators, and meters. This equipment often has long lead times, which in many cases have been increasing due to global supply chain and raw material issues. To ensure we can provide electrical service when critical equipment fails or to connect new customers, the Company plans and maintains necessary inventory levels of critical electrical system equipment.

Q37. What capital expenditures fall into the NRUC and Improvement Blankets subcategory?

A37. The expenditures that fall into this subcategory include: (1) System Improvements, (2) Normal Retirement Unit Change-Out (NRUC), and (3) Operational Technologies.

1. System Improvement projects are focused on reducing the frequency and duration of customer outages. Unlike larger scale, longer time frame projects like conversions or subtransmission projects, they are smaller scope projects managed by regional operations to immediately address localized

customer issues and complaints. These projects do not exceed $350,000 and do not require extended planning and design.

2. Normal Retirement Unit Change-Out (NRUC) consists of projects to perform scheduled work that replace assets determined by equipment engineers to be at end-of-life.
3. Operational Technologies consists of the infrastructure and associated applications that support the AMI platform and data. This also covers annual work in testing new meter types, designing and installing configurations, replacing communications equipment, and testing changes for new equipment.

Q38. Has the Company analyzed the customer connections, relocations & other program and re-assigned program investment areas that do not fully align with the purpose of this category?

A38. Yes. The Company removed Animal Mitigation and Batteries and Charges from Customer Connections, Relocations & Other to strategic capital. The Company will continue to review its project categorization and adjust in the future to help ensure alignment of investment categories.

Q39. What capital expenditures fall into the General Plant, Tools & Equipment, and Miscellaneous subcategory?

A39. General Plant, Tools & Equipment, and Miscellaneous includes new tools as well as beyond useful life replacement tools required for field workers to perform their tasks. It also includes engineering test equipment and substation physical security.

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These expenditures ensure that Company workers have the necessary tools and equipment to conduct and construct field work. Examples of items include meters, phase sets, and infrared cameras. It also includes DC hi-potential testers (Hipoters) that are used to test insulation on cable, breakers, transformers, etc.

Q40. What was the Public Lighting Department Project?

A40. The Public Lighting Department (PLD) project converted former PLD customers to the Company's distribution system. This project included extending the Company's overhead and underground system by performing activities like transformer replacements and line extensions. This project was completed with \$1.9 million of investment in 2023 (Exhibit A-12, Schedule B5.4, page 1, line 14, column (c)) with the removal of three breakers from Waterman substation and final connection of the Detroit Institute of Art (DIA).

Q41. What is the Incremental Infrastructure for Electric Vehicle (EV) capital investment in Exhibit A-12 Schedule B5.4 on page 4, line 29 within Customer Connections?

A41. In Case No. U-20836, the MPSC requested DTE Electric to "prepare and submit in its next rate case, a full scale, well-developed, permanent Charging Forward proposal that includes a BCA [benefit cost analysis]."

In response, Company Witness Bennett and her team has developed a comprehensive Transportation Electrification Plan, with the goal to power and enable a cleaner energy future for its customers through transportation electrification.

Incremental Infrastructure for EV consists of capital investments of $4.7 million in 2024 and $11.4 million in 2025 needed to build out EV charging infrastructure, which is a subset of the DTEE 2023 Transportation Electrification Plan. This capital investment is supported by Company Witness Bennett's testimony in Section 2 The Company's Proposal for a Transportation Electrification Plan and called out in Answer 71.

Q42. What work is the Company performing to comply with the Commission's Order No. U-21297 regarding line extensions?

A42. The Company has reviewed Section 6 of the Rate Book with respect to customer Contribution in Aid of Construction (CIAC) costs and updated them in Table 5 below. These costs represent current cost per foot or cost per kVA developed using compatible unit estimates for associated labor and material costs. Refundable costs capture the full cost of construction and non-refundable costs represent cost differentials between overhead and underground construction.

1 **Table 5. Line Extension Cost Updates**

Section of Rate Book	**Page**	**Element to be updated**	**Current Rate**	**Updated Rate**
C6.2(1b)	C-28	Refundable construction advance of $6.50 per foot	$6.5	$16.91
C6.3(A)(14)	C-33	$1.00 per trench foot added for winter construction	$1.0	$1.0
C6.3(B)(2)	C-34	multiplying the sum of the lot front footage for all lots in the subdivision by $3.00	$3.00	$18.30
C6.3(B)(6)(a)	C-35	$3.00 per lot front foot for the total front footage	$3.00	$18.30
C6.3(C)(2)(a)	C-36	lot front footage for all lots in the park by $3.00	$3.00	$18.30
C6.3(C)(2)(c)	C-36	Transformers - $7.50 per kVA, for the total nameplate kVA installed.	$7.50	$18.47
C6.3(D)(2)(a)	C-37	total length of trench feet required for distribution facilities by $4.30 plus $7.50 per kVA (nameplate) of transformer capacity to be installed.	$4.30 per trench ft + $7.5 per kVA	$17.84 per trench ft + $18.47 per kVA
C6.3(E)(2)(a)	C-38	total length in feet multiplied by $4.30	$4.30	$17.84
C6.3(E)(2)(b)	C-38	Transformers will be charged on an installed basis of $7.50 per kVA	$7.50	$18.47
C6.4(A)	C-38	$300 for trench lengths up to 200 feet	$300	$730
C6.4(A)	C-38	$3.90 per foot for each additional foot added	$3.90	$9.48
C6.4(B)	C-39	$3.90 per foot for each additional foot added	$3.90	$9.48
C6.4(C)	C-39	trench length in feet multiplied by $4.30	$4.30	$17.84
C6.4(C)(2)(b)	C-39.01	multiplying the horizontal length of the service lateral in feet by $10.00.	No Change	
C6.4(C)(3)(c)(a)	C-39.02	$4.30 per trench foot	$4.30	$17.84
C6.4(C)(3)(c)(c)	C-39.02	$15 per kVA for all dry type transformers.	No Change	

C6.4(D)(1)(c)	C-40	multiplying the horizontal length of the service lateral in feet by $10.00	No Change	
C6.5(A)(1)(a)	C-42	0.48 per kVA of installed transformer capacity for the first 10kVA	No Change	
C6.5(A)(1)(b)	C-42	0.12 per kVA of installed transformer capacity for excess of 10kVA	No Change	
C6.6(H)	C-45	Recalculate if more than $1 for customer, or more than $2 for someone no longer customer.	No Change	

<u>**Part III Portable Generators**</u>

Q43. What are the Portable Generators in Exhibit A-12, Schedule B5.4, page 13, line 28 under the Infrastructure Resilience and Hardening pillar?

A43. The $4.5 million for Portable Generators in 2024 is to purchase generators that the Company will deploy to customers to provide temporary electricity during storms. The company will prioritize generators to customers based on the estimated duration of storm outage, customer medical needs, and other factors.

Deployment of generators will not be done by lineworkers and therefore will not impact restoration time for our customers. Most of the generators allow customers to use devices that draw less than 2,000 watts. This typically includes items like refrigerators, freezers, personal medical devices, and sump pumps.

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Part IV Miss Dig

Q44. What did the Commission order regarding the tracking of infrastructure strikes related to Miss Dig in Case No. U-21297?

A44. The MPSC Staff recommended, and the Commission Ordered the following concerning Miss Dig in the Order No. U-21297, page 376, dated December 1, 2023: "Pertaining to the Miss Dig program, DTE Electric Company shall commence tracking and keeping records of expenditures incurred from damages caused by the company to its own facilities; work with the Commission Staff to share damage reporting data including the billing amounts for damages when a third-party causes damages and expenditures for damages, and for sharing billing amounts when the company causes damages; include a breakdown of damage prevention expenditures in future general rate cases under Federal Energy Regulatory Commission account 580 including, but not limited to, internal locating and contract locating in future general rate cases; and improve the company's damage reporting quality by continuing to meet with the Commission Staff regarding damage report data and committing the time and resources to submitting data into the format that aligns with the Commission's processes."

Q45. How is the Company responding to these Miss Dig expenditures tracking and reporting requirements that were Ordered in Case No. U-21297?

A45. The Company is actively working on plans to comply with the recommendations and reporting requirements. The Company met with MPSC Staff during Case No. U-21297 and continues to meet with Staff on a bi-monthly basis.

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Q46. What progress has the Company made since the Case No. U-21297 Order?

A46. The Company updated the formatting and data in the Miss Dig damage report. This report includes information on damage claims by responsible party, the amount of damage/expenditures, and causes of the damage. This information is shared monthly and reviewed during meetings with MPSC Staff and enables open dialogue on damage prevention. The report includes first party damages caused by the Company to its own facilities. The Company will continue monthly meetings with MPSC Staff to further make additional improvements and comply with the order.

Q47. Does this complete your direct testimony?

A47. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ALLEN J. KRYSCYNSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ALLEN J. KRYSCYNSKI

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Allen J. Kryscynski (he/him), and my business address is One Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I earned a Bachelor of Science from the University of Michigan School of Natural Resources and Environment with a dual concentration in environmental policy and natural resource management. I also received a master's degree in Business Administration (MBA) from the University of Michigan.

Q4. Please summarize your professional experience.

A4. I held several positions with ITC Holdings including Senior Regulatory Analyst and a variety of positions within the Local Community and Community Affairs team culminating as a Senior Local Government and Community Affairs Representative. At ITC Holdings, I worked on FERC and MISO regulatory issues and represented ITC Holdings at community meetings to gain approval for new transmission substations and transmission lines.

I joined DTE Energy in 2014 as a Strategy and Corporate Development Associate in the Corporate Strategy group. In this role, I did work on the initial Distribution Operations (DO) investment strategy project to determine distribution grid

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investment needs as well as work on DTE workforce projections and requirements for both the Distribution Operations and Fossil Generation business units. In 2016, I was appointed Manager of Distribution Operations Strategy and assumed responsibility for continued work to evolve the distribution operations investment strategy, operations strategy, and the chief of staff role for the Senior Vice President of Distribution Operations. In early 2018, I was appointed Manager in Project Management with responsibility to start up and operationalize the 4.8kV Hardening Program to remove City of Detroit Arc Wire and harden the City of Detroit electrical infrastructure. Later in 2018, I was appointed Manager of Tree Trim Strategy where I was responsible for managing the initial Tree Trim Surge rate case, Tree Trim contractor negotiations, and the overall Tree Trim strategy for scheduling work, and ensuring there was an adequate supply of tree trimmers necessary to complete the work. In 2020 I took over the Tree Trim Operations Manager position and managed day to day Tree Trim operations including overseeing all of DTE's internal arborists and foresters as well as eight tree trim contractors and their 1,600+ employees. In 2022 I was appointed as Manager of Distribution Operations Regulatory Strategy and Grid Modernization and promoted to Acting Director in 2023.

Q5. What are your current duties and responsibilities?

A5. As Director of Distribution Operations Regulatory Strategy and Grid Modernization, my current responsibilities are two primary focus areas: 1) managing Distribution Operations regulatory activities – including rate cases, the distribution grid plan filing, required reporting, and various Company/MPSC collaboratives, and 2) Distribution Operations long term grid modernization strategy and the distribution grid plan (DGP).

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in Case No. U-21297. In addition, I supported Tree Trim testimony and witnesses in U-20162, U-20561, and U-20836.

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support, as reasonable and necessary, the historical Operations and Maintenance (O&M) expenses related to electric distribution activities for 2022 historical period and for the projected test period 12-months ending December 31, 2025. Additionally, my testimony describes the (1) Distribution Operations Overview which includes an introduction to the other witnesses from Distribution Operations in this case and System Performance, Overview, (2) Distribution Rate Request, (3) Distribution O&M, (4) Distribution Grid Plan (DGP) Overview, (5) Strategic Capital Overview, (6) Overview of the capital exhibits – Exhibit A-12 Schedule B5.4, and Exhibit A-23 Schedules M4, M5, M6, and M7, (7) Variances between the 2022 actuals and the forecast in Case No. U-21297 in Exhibit A-12 Schedule M1; projected capital expenditures forecasted in Case No. U-21297 for calendar years 2023 and 2024 and the project capital expenditures in this case for calendar years 2023 in Exhibit A-12 Schedule M2 and 2024 in Exhibit A-12 Schedule M3, (8) Distribution Operations' Global Prioritization Model (GPM) and Exhibit A-23 Schedule M14, (9) the Company's Capital/Reliability Projection Model (10) Infrastructure Investment and Jobs Act (IIJA) funding grants, (11) Updates on the Distribution Operation's approach to Environmental Justice (EJ), and (12) Coordination Processes in place with local municipalities.

I will discuss the capital exhibits and overview while the reasonableness and prudence of each specific capital investments will be supported by other DO witnesses.

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Q8. How is your testimony organized?

A8. My testimony consists of twelve parts:

Part I	Distribution Operations Overview and System Performance
Part II	Distribution O&M and Capital Rate Request
Part III	Distribution O&M Overview and Exhibits
Part IV	Distribution Grid Plan (DGP) Overview
Part V	Strategic Capital Overview
Part VI	Capital Exhibits Description
Part VII	Capital Investment Variance Discussion
Part VIII	Global Prioritization Model
Part IX	Capital/Reliability Model
Part X	IIJA Grant Opportunities
Part XI	Environmental Justice
Part XII	Municipal Project Coordination

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-23	M1	U-21297 2022 Forecast vs. U-21534 Comparison
A-23	M2	U-21297 2023 Forecast vs. U-21534 Comparison
A-23	M3	U-21297 2024 Forecast vs. U-21534 Comparison
A-23	M8	2023 Distribution Grid Plan, MPSC Case No.

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		20147
A-23	M14	GPM Project and Program Rankings

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

<u>Part I: Distribution Operations Overview and System Performance</u>

<u>Distribution Operations Organization</u>

Q11. Can you please describe the organization that manages the investments included in the exhibits you are sponsoring?

A11. Distribution Operations (DO) is the organization that manages the investments included in the exhibits I am sponsoring. The organization focuses on the design, maintenance, and operation of the Company's electrical distribution system and subtransmission system, which together are often referred to as "the distribution system." DO is comprised of nine suborganizations, described below.

(i) Central Engineering: This organization is responsible for determining, maintaining, and improving the health of the Company's electric distribution assets, which includes defining technical standards for distribution equipment, long-term system planning including grid modernization, and developing major projects needed for customer connections, relocations, increasing loads, infrastructure improvements, reliability upgrades, and technology enhancements.

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(ii) Regulatory Strategy and Grid Modernization: This organization is responsible for two primary areas of focus: 1) Distribution Operations' long term grid modernization strategy and the distribution grid plan (DGP) and, 2) Distribution Operations regulatory activities – including rate cases, the distribution grid plan filing, MPSC required reporting, and conducting and organizing the numerous collaborations ordered by the MPSC.

(iii) Scheduling & Construction: This organization is responsible for: 1) scheduling all planned work for both DTE and contractors' field crews on overhead and underground distribution, subtransmission, and substation assets; 2) leading systematic approaches to track and measure work, streamlining business processes and routine tasks, and governing the Maximo Business Process that coordinates team collaboration and workflows across all levels of the organization; 3) planning, and field oversight of out-of-state storm resources when required for large storm events; 4) contractor accounts payable and invoicing, unitization of capital investments, and conducting field quality inspections to validate construction is built to standards and specifications; 5) governance of the DO Safety, Human Performance, and Hazardous Energy Control programs.

(iv) Operational Technology: This organization is responsible for Advanced Metering Infrastructure (AMI) system enhancements and operations, meter engineering and metrology, equipment calibration, grid mapping including analytics, and working with business units within Distribution

Operations to define, implement, and support technology and analytical solutions including our Storm Excellence investments in support of our storm restoration efforts. The organization also manages the Advanced Distribution Management System (ADMS), which provides the technological capabilities to monitor and operate the grid, respond to emergency conditions and outages, and facilitates the deployment of distributed energy resources.

(v) Regional Customer Operations: This organization is responsible for overhead and underground emergent work, short-cycle (typically less than a year) construction, new service and meter installations, and design and planning focused on short-cycle reliability, and customer-requested work.

(vi) System Operation: This organization includes the Company's Electric System Operations Center (ESOC), where DTE Electric monitors and controls the electrical system to maintain a reliable and secure flow of electric power.

(vii) Emergency Preparedness & Response "EPR": This organization plans efforts to reduce the time customers spend without power and develops, maintains, manages DO's incident response procedures and storm events and enhances storm process for customers through improved communication. EPR has expanded the organization with a pointed focus on improving storm restoration processes and enhancing the Company's ability to efficiently restore customers in "extreme weather" scenarios, such as recent storms our customer base has been experiencing. EPR is comprised of six groups (strategy, public safety, damage assessment, Regional ICS, Productivity, and Event management). The team has set individual targets within each group and has initiated projects focused on addressing the gaps identified from previous storms. All of this work is aligned to a broad strategic plan focused on improving day to day emergent operations and storm processes.

(viii) Tree Trimming: This organization plans, communicates, and implements the Company's tree trimming program.

(ix) Substation Operations: This organization is responsible for the operation and maintenance of all the substations within the DTE Energy service territory.

Q12. Have there been any significant changes to the DO organization since the filing of U-21297?

A12. Yes. To better support the increasing construction for grid investments, a Project Management Office (PMO) was created by merging the DO project organization with DTE's Major Enterprise Projects (MEP) group to consolidate project management expertise in one group. This new organization is responsible for management and execution of the majority of Strategic Capital projects and programs for Distribution Operations, as well as large investment projects for other areas of DTE. The organization consists of the project managers, cost engineers, schedulers, project estimators, and the leadership/support teams required to manage and track the progress of DO's capital investments. The PMO has focus on driving cost efficiency, managing project scope and schedule, and is specifically targeting challenges in labor cost and availability, supply chain constraints and material availability, as well as obtaining needed land, permits, and easements. Some smaller programs and projects are still managed within the DO organization.

Q13. How is the Distribution Operations testimony organized in this case?

A13. Distribution Operation (DO) capital and O&M expenditures, as well as other activities, are supported by six (6) witnesses in this case. Together these witnesses discuss the reasonableness and prudence of DO capital and O&M expenditures, exhibit content, tree trim, Environmental Justice (EJ), and other topics related to DO. A high level summary of these six witnesses' scope of testimony is introduced below:

1) Witness Allen J. Kryscynski is the Distribution Operations Regulatory Strategy and Grid Modernization. The purpose of my testimony is described above.
2) Witness Brian Hill is the Director Southwest Regional Customer Operations and Scheduling & Coordination. The purpose of witness Hill's testimony is to support as reasonable and prudent the investments in base capital programs, Emergent Replacements and Customer Connections, Relocations & Other.
3) Witness Morgan Elliott Andahazy is the Director of PMO Programs. The purpose of witness Elliott Andahazy's testimony is to support, as reasonable and prudent, investments in the strategic capital pillar Infrastructure Resilience and Hardening.

4) Witness Satvir Deol is the Director of Engineering. The purpose of witness Deol's testimony is to support, as reasonable and prudent, investments in the strategic capital pillar Infrastructure Redesign and Modernization.
5) Witness Shannen Hartwick is the Director of Automation for DO. The purpose of witness Hartwick's testimony is to support, as reasonable and prudent, investments in the Technology and Automation pillar including Grid Automation, Grid Automation Telecommunication, AMI and ADMS projects, and the Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC) projects, and other operational technology investments.
6) Witness Rachel Steudle is the Director of Tree Trim. The purpose of witness Steudle's testimony is to (1) discuss the importance of and progress made in DTE Electric's vegetation management ("Tree Trimming") program, (2) provide details related to the Company's Tree Trimming Surge Program that will deliver on the reliability goals established in the Company's Distribution Grid Plan (DGP), (3) describe the customer benefits of the Company's Tree Trimming Surge Program to date, (4) support the Operations and Maintenance (O&M) expenses related to tree trimming efforts for the historical test period ending December 31, 2022, and the projected base O&M expenses and the Tree Trimming Regulatory Asset Surge funding amount for January 1, 2025, to December 31, 2025, (5) request approval of incremental Surge funding for 2025, (6) discuss the future of the Tree Trimming program once the Surge is completed, (7) address the additional requests from U-21297.

Electrical System Overview

Q14. Can you briefly describe the electrical system that the Company owns and operates?

A14. The Company owns and operates approximately 31,000 miles of overhead subtransmission and distribution lines, and 16,830 miles of underground subtransmission and distribution lines. The Company's service territory encompasses approximately 7,600 square miles and includes approximately 2.3 million residential, commercial, and industrial customers. Additional key statistics are listed in **Tables 1 – 4**.

Table 1 DTE Electric Substations by Type and Voltage

Substation Type	Total Number of Substations	Number of Substations by Circuit/Low Side kV							
		4.8	8.3	13.2	4.8& 13.2	24	40	24& 40	Other
General Purpose	542	244	4	243	30	4	13	3	1
Single Customer	145	49	0	86	1	0	0	0	9
Customer Owned	102	NA	NA	NA	NA	NA	NA	NA	NA
Total	**789**	**293**	**4**	**329**	**31**	**4**	**13**	**3**	**10**

Table 2 DTE Electric Transformers by Voltage Level

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	178	13,085,000
Substation - Distribution	1,449	24,093,221
Distribution - Overhead and Pad-mount	451,919	33,078,863
Total	**453,546**	**70,257,084**

Table 3 Distribution Circuits and Line Miles

Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles	Total Customers
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV		
13.2 kV	1,269	11,796	16	5,596	10,710	1	417	28,535	1,030,999
8.3 kV	13	0	45	0	1	18	0	63	8,202
4.8 kV	1,991	31	0	11,064	274	0	1,937	13,307	1,213,025
Total	**3,273**	**11,828**	**60**	**16,660**	**10,985**	**18**	**2,354**	**41,905**	**2,252,226**

Table 4 Subtransmission Circuits and Line Miles by Substation Bus

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	466	2,819
24 kV	242	177	732	909
Total	636	2,589	1,206	3,795

Voltage

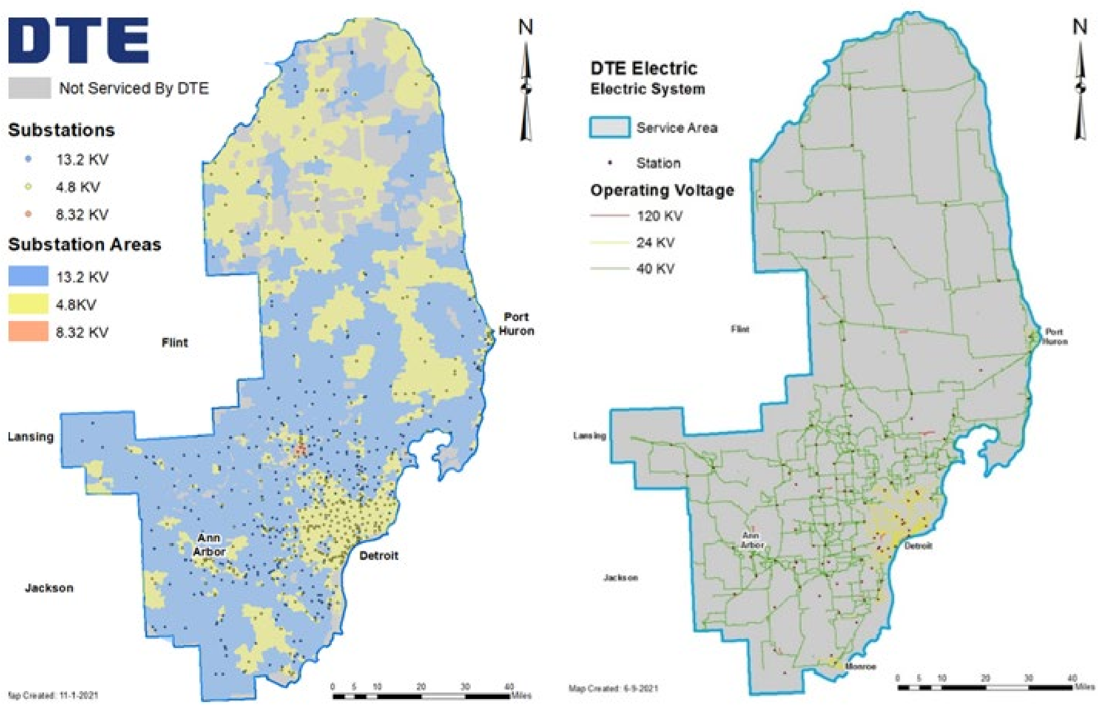
Q15. What is the difference between the Company's distribution and subtransmission voltages?

A15. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution levels, although some larger industrial customers are fed directly from subtransmission. The Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and this infrastructure is designed to feed the circuits that provide power to customers.

Q16. How are the Company's distribution and subtransmission voltages distributed throughout the service territory?

A16. **Figure 1** illustrates the location of the Company's substation equipment voltages. There are some substations that operate at 13.2kV but have parts of circuits that operate at 4.8kV.

Figure 1 Location of Distribution Projects Based on Subtransmission Voltages



Q17. What is the age of the Company's distribution system assets?

A17. **Table 5** provides the average age and age range of the Company's key distribution assets along with the life expectancy and demonstrates that the Company's assets are relatively aged. For some asset classes, poles for example, the average age and the industry life expectancy of the asset are close to the same which can be an indicator of challenges to current and future equipment health. While not the only factor impacting reliability, age can become a significant factor when replacement parts become unavailable or in the specific cases where asset health deteriorates sharply with age. Eight of the 18 asset classes have an average age at or near the life expectancy.

Line
No.

Table 5 Asset Age Summary

Asset (Section)	DTE Electric Age Range (Years)	DTE Electric Average Age (Years)	Life Expectancy (Years)	% of Asset Class at or Beyond End of Life
Substation Power Transformers	0-99	43	40-45	49%
Network Bank Transformers	0 – 85+	46	20 - 30	91%
Circuit Breakers	0 – 90	41	30 – 40	60%
Circuit Switchers	0 – 36	19	NA	NA
Relays	0-60+	33	15-50	NA
Switchgear	0 – 70	40	40	55%
Poles	0-90+	48	40-50	50%
Three-phase Reclosers	0-34	10	20	10%
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	0-31	15	20	38.5%
40 kV Automatic Pole Top Switches	0-50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable	0 – 100+	49	20 – 40	64%
Underground Residential Distribution (URD) Cable	0 – 60+	26	40	23.6%
Manholes	1-100+	78	Varies based on construction and field conditions	NA
Advanced Metering Infrastructure (AMI meters)	0-13	6.5	20	0%

Line
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Q18. As shown in Table 5, how has the Company determined industry end of life expectancy?

A18. The Company's internal subject matter experts draw from a broad set of sources to determine equipment life expectancy, including ongoing review of technical papers, attending industry working groups, meeting with manufacturers, and gaining specific experience with the performance of the assets on the Company's electrical system.

Q19. Is age the only factor to consider when selecting assets for replacement?

A19. No. Age is just one of the factors considered when determining asset health and the need for equipment replacement. There are instances where younger equipment is at higher risk of failure, for example due to specific known equipment issues, and is selected for replacement ahead of more aged equipment. Additionally, there are many instances where the Company assesses older equipment and finds that it still can safely and reliably remain in service and serve customers. However, age is a factor used throughout industry as one measure of asset health.

System Performance

Q20. How does the Company and industry measure system reliability?

A20. The Company uses industry standard reliability metrics that are defined by the Institute of Electrical and Electronics Engineers (IEEE) standard 1366[1]. DTE Electric measures overall system reliability using the indices System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). These

[1] Microsoft PowerPoint - Without video IEEE 1366- Reliability Indices 2-2019.pptx available at https://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf

indices are typically calculated in two ways: 1) All-Weather conditions, and 2) excluding Major Event Days (MEDs). An MED is any 24-hour period in which there is a significant statistical difference in daily SAIDI. Excluding MEDs from the indices offers a more accurate comparison between time periods and to other utilities because it gives the Company a clear picture of day-to-day system performance and customer experience absent significant weather events – which are highly variable in size, impact, and system location from year-to-year and. The Company's primary metric for measuring system reliability is the System Average Interruption Duration Index (SAIDI). SAIDI is defined by IEEE as the total time (in minutes) of all customer interruptions divided by the total number of customers served. SAIDI measures the average time that customers are without power in a year because it is calculated using both the frequency and the duration of interruptions. SAIFI is calculated by dividing the number of customer interruptions by the number of customers served. SAIFI measures the average number of sustained interruptions experiences by the system's average customer. CAIDI is calculated by dividing the sum of customer interruption duration by the total number of customer interruptions. CAIDI measures the average time required to restore power to the average customer who experiences an outage.

Q21. What are the recent reliability metric trends for the Company's electrical system?

A21. **Figure 2** through **Figure 5** show the distribution system performance from 2017 to 2023 for SAIDI-All Weather, SAIDI-Excluding MEDs, SAIFI-All Weather, and SAIFI-Excluding MEDs. As shown in **Figure 2** and **Figure 3**, the Company performed in the 4th quartile in All-Weather SAIDI and 3rd quartile for SAIDI-

Line
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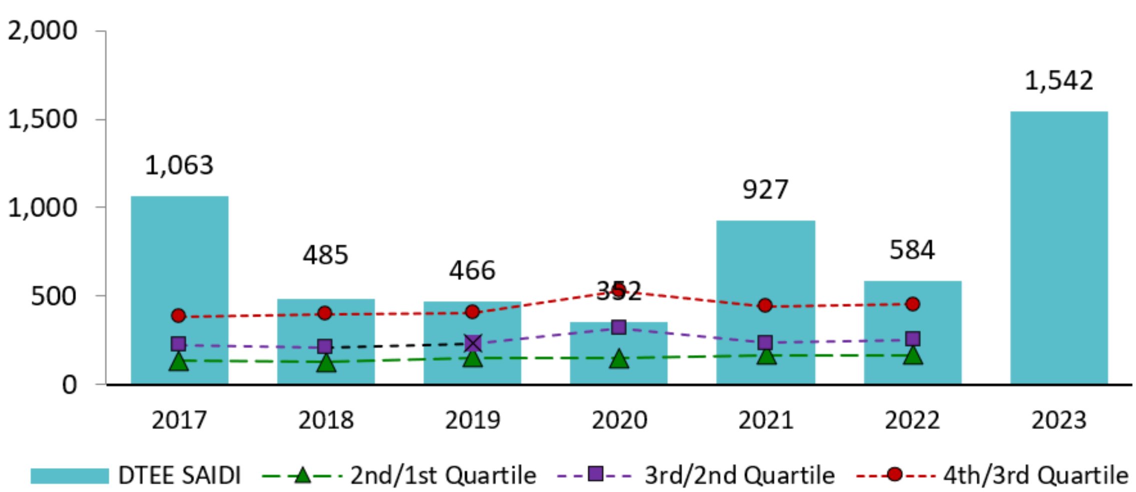
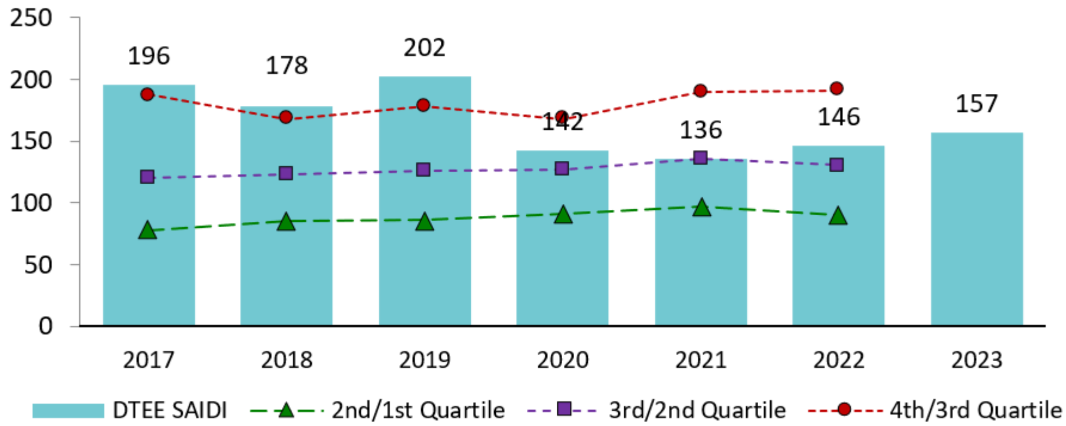
Excluding MEDs for 2023. The Company has been, except for 2020, in the fourth quartile for SAIDI-All Weather for the seven years shown on **Figure 2** below. As shown in **Figure 4** and **Figure 5**, the Company performed in the 3rd quartile in All-Weather SAIFI and 2nd quartile for SAIFI-Excluding MEDs for 2023. SAIFI-All Weather has been in the second quartile four of the last seven years. Benchmarking quartiles are not yet available for 2023 so all quartiles refenced for 2023 are compared to the 2022 benchmarking numbers. CAIDI can be calculated by dividing SAIDI by SAIFI. Benchmarking is performed by the Institute of Electrical and Electronics Engineers (IEEE) and made available to its members annually.

Figure 2 **All Weather SAIDI Performance* (Minutes)**



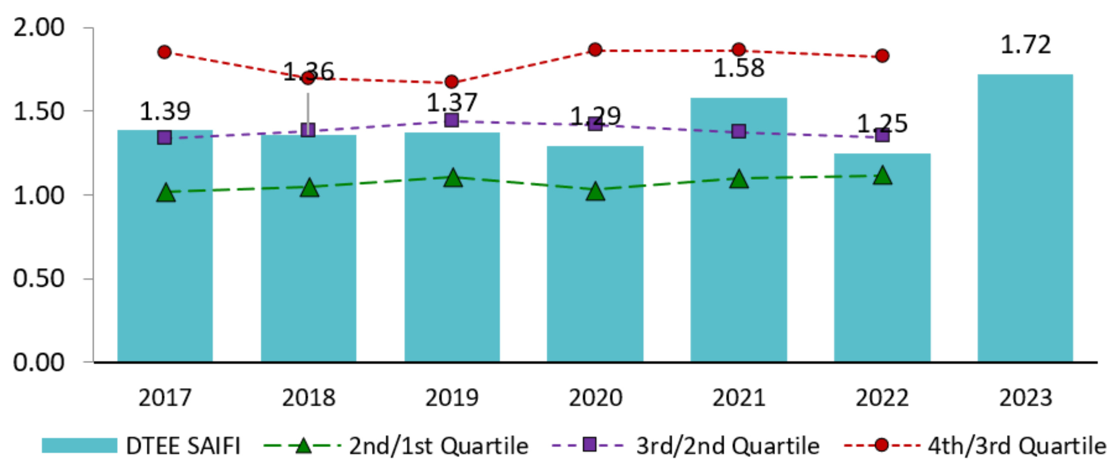
*Quartile information for 2023 is not yet available

Figure 3 SAIDI Ex-MED Performance* (Minutes)



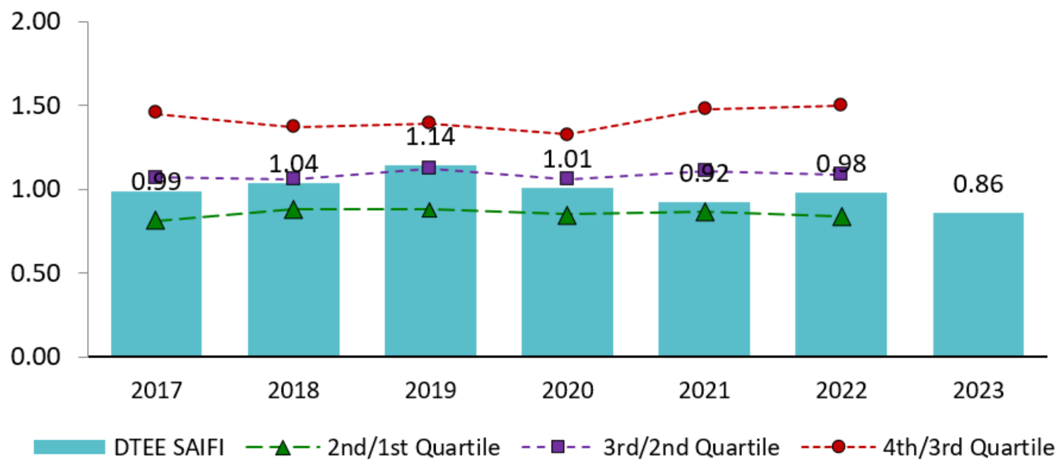
*Quartile information for 2023 is not yet available

Figure 4 All Weather SAIFI Performance*



*Quartile information for 2023 is not yet available

Figure 5 SAIFI Ex-MED Performance*



*Quartile information for 2023 is not yet available

Q22. What large weather events impacted the Company's reliability performance in 2023?

A22. This past year, 2023, brought additional large storm events including back-to-back storms in February, first ice and then snow, that left over 675,000 customers without power for extended periods of time. These two storms alone contributed 730 minutes of All-Weather SAIDI to the annual metric, more than all SAIDI minutes recorded in 2022. However, if the volatility of the extreme weather is removed, SAIFI and SAIDI Excluding MEDs remain in the second quartile indicating that the Company's non-storm performance is stable. See Witness Hill's testimony for additional discussion on 2023 storm impacts.

Q23. How have previous strategic investments impacted reliability performance?

A23. Positively. To name a few examples, the Company has seen improved reliability results in areas that have had their Surge Tree Trim program, 4.8kV Hardening, and Frequent Outage Programs. These programs and reliability improvements are discussed in Witness Steudle and Witness Elliott Andahazy's testimony.

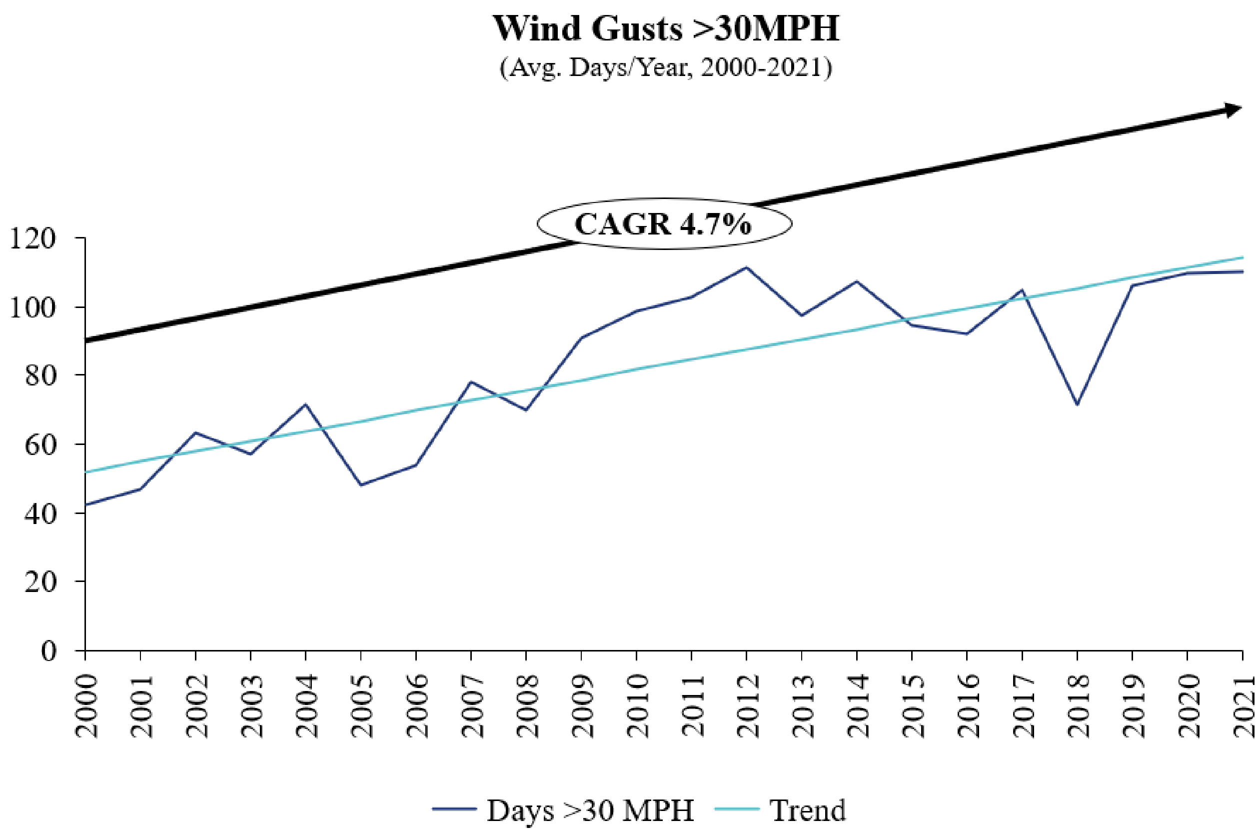
Q24. What are the primary challenges the Company faces with respect to reliability improvements?

A24. There are three primary challenges:

- First, the Company has seen an increase in the number of high wind speed days which adds additional stress to the already aged fleet of equipment and provides more opportunity for failures **(Figure 6**).
- Second, the system continues to get older. The average pole age has increased from 40.7 years in 2012 to 47.9 in 2024 – See **Figure 7**. Notably, the slope of the line becomes less steep starting in 2022, indicating the average pole age increased at a slower rate as the Company increased investment in 4.8kV Hardening, PTMM, and 4.8kV Conversion. Continued investments in these programs is needed in order to continue to decrease the rate at which the Company's assets are aging. The pole equipment age curve was selected as a representative sample of the Company's overhead equipment health. DTE will continue to invest in the rebuilding the overhead system to flatten and bend down the age curve.
- Third, the Company is early on its journey to stabilize and rebuild the grid. While the Company has made progress to date, increased, sustained investment will be needed to improve and then maintain reliability. The Company's 2023 DGP provides a path forward to both improve near-term

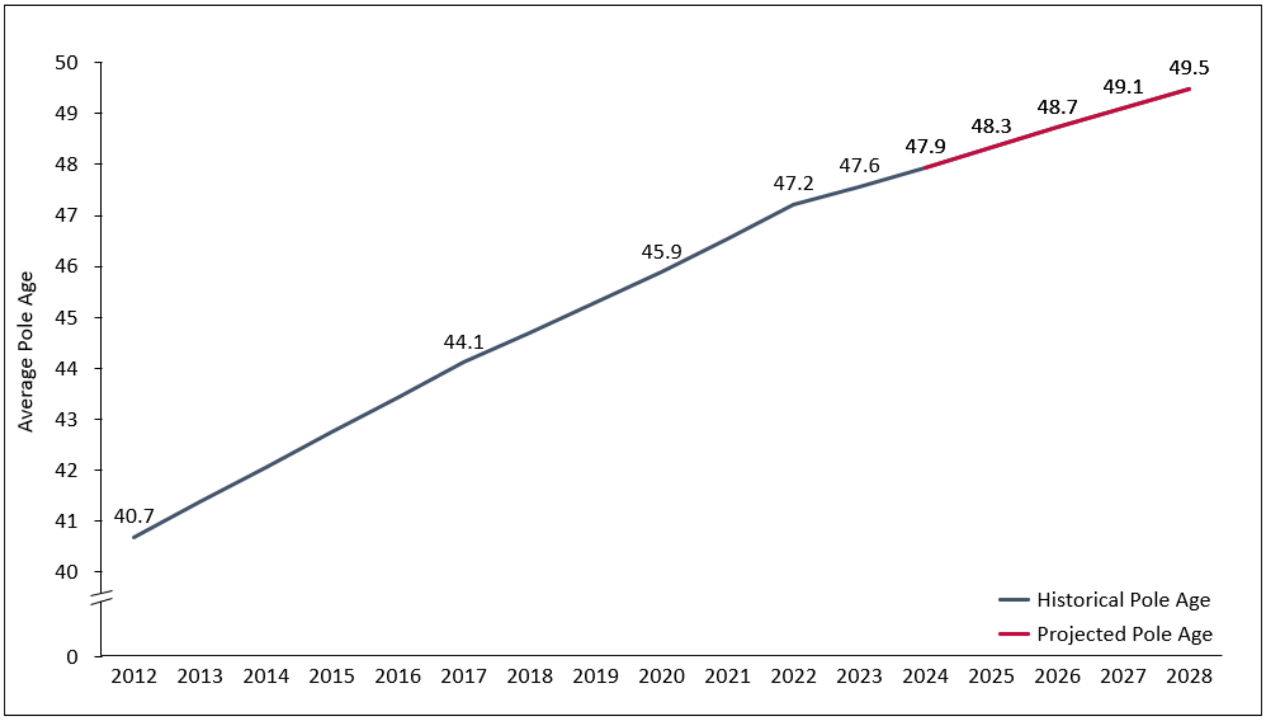
reliability and provides a roadmap for the required investment necessary maintain long-term reliability.

Figure 6 Michigan[2] Wind Gusts 2000-2021



[2] Data from https://mesonet.agron.iastate.edu/request/daily.phtml. SE region represented by Detroit Metro, SW region represented by Ann Arbor, NW region represented by Pontiac.

Figure 7 Historical and projected pole age[3]



Q25. What changes were made to the Company's investment strategy based on the 2023 weather events and system age and deterioration?

A25. The Company has increased its investment plans in both PTMM, 4.8kV Hardening and Automation in order to target near and mid-term improvements in fundamental grid resiliency and restoration. Long-term work such as conversions will continue to support rebuilding the grid to increase system resilience and support needed capacity. The Company is also working to improve storm restoration processes,

[3] Projected pole age assumes 2025-2028 strategic investment levels for PTMM, 4.8kV Hardening and 4.8kV Conversion are the same as the 2024 investments planned in the case. Poles replaced on base capital, including emergent replacements, are assumed to be constant.

including ADMS Enhancements, to be able to respond to storm events more quickly.

Part II: Distribution O&M and Capital Rate Request

Q26. What O&M and capital is the Company asking the Commission to include in rates related to Distribution Operations?

A26. The Company is including $359.2 million of operation and maintenance (O&M) expenses in the projected test period as shown in Exhibit A-13, Schedule C5.6, Page 1, Line 27.

The Company is requesting $3.14 billion of capital investments for the 24-month bridge period ending December 31, 2024 and $1.63 billion of capital investments for the 12-month projected test year ending December 31, 2025, as shown in Exhibit A-12, Schedule B5.4, Page 1, Line 23, supported and sponsored by witnesses Hill, Elliott Andahazy, Hartwick, Deol, and Steudle in base rates.

Q27. Why are the levels of capital and O&M proposed by the Company necessary?

A27. The levels of capital investment and O&M expense are necessary to achieve the Company's goals of providing safe, reliable, and clean electricity to our customers at reasonable rates. These investments also lay the foundation for grid modernization, needed to support our customers' evolving needs for greater resiliency in the face of increasingly frequent and intense storms, electrification including electric vehicles (EVs), and the integration of distributed energy resources (DERs).

Line
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Part III: Distribution O&M Overview and Exhibits

Q28. What does Exhibit A-13, Schedule C5.6, "Projected Operation and Maintenance Expenses – Distribution Expenses" show?

A28. This schedule reflects the operations and maintenance costs for DO, which are primarily driven by systems operations costs (including operating the System Operations Center which monitors and controls the subtransmission and distribution grids), addressing day-to-day trouble and storm restoration, tree trimming, equipment preventative maintenance and other system maintenance requirements. The expenses shown in this exhibit represent both DO and street lighting. Company Witness Bellini provides testimony addressing the streetlighting costs, and Company Witness Steudle supports DO's tree trimming expenses. I am supporting all other DO expenses.

Q29. Can you provide a brief explanation of the items listed under Distribution Expenses in Exhibit A-13, Schedule C5.6?

A29. The costs associated with dispatching, coordinating restoration, and tree trim efforts are included in FERC accounts 580 (Operation Supervision and Engineering) and 581 (Load Dispatching). Accounts 582 (Station Expenses), 583 (Overhead Line Expenses), 584 (Underground Line Expenses), and 588 (Miscellaneous Expenses) incorporate the costs for developing and implementing training and work force planning for the Company's substation operators and maintenance personnel, apprentice lineman, splicers, technicians, engineers, riggers, and planners as well as the staff groups to support these critical efforts. Job skills training is conducted for the safety of employees and the public. Witness Bellini supports account 585 (Street Lighting and Signal System Expense). Meter testing and distribution costs are incorporated into account 586 (Meter Expenses). Account 587 (Customer Installations Expenses) includes expenses to support the specific needs of customers served at primary voltages. Account 589 (Rents) reflects the expenses associated with leased facilities and the Company attaching to poles not owned by the Company.

Q30. What do the line items listed under Maintenance in Exhibit A-13, Schedule C5.6 describe?

A30. Maintenance costs are critical to providing safe and reliable service. Account 591 (Maintenance of Structures) is to support the maintenance of existing physical structures associated with the electric distribution system. Restoration, troubleshooting and reactive maintenance work associated with substation, overhead and underground equipment is included in accounts 592 (Maintenance of Station Equipment), 593 (Maintenance of Overhead Lines), and 594 (Maintenance of Underground Lines) respectively. In addition, account 593 includes the tree trim expenses supported by Company Witness Steudle. The supervision and other support costs for these important efforts are included in account 590 (Maintenance Supervision and Engineering). Company Witness Bellini supports account 596 (Maintenance of Street Lighting and Signal Systems).

Q31. How are the 2022 historical O&M and the projected test period O&M expenses for DO shown on Exhibit A-13, Schedule C5.6?

A31. Exhibit A-13, Schedule C5.6, page 1, summarizes the 12-month period ended December 31, 2022 actual O&M expense and the projected O&M expense for December 31, 2023 through December 31, 2025. Line 27, column (c) provides the total actual unadjusted O&M expenses for the 12-month historical test period ended December 2022.

Q32. What are the adjustments in columns (d) and (e) of Exhibit A-13, Schedule C5.6, page 1?

A32. The adjustments in column (d) reduce the total historical test year O&M expenses by the amounts related to the Transitional Reconciliation Mechanism (TRM) costs, which are included in accounts 566 and 588. In column (e) the adjustment on line 20 is to normalize restoration expenses, see below. The total results of columns (d) and (e) are added with column (c) to produce column (f).

Q33. What are the adjustments in columns (g) through (i) of Exhibit A-13, Schedule C5.6, page 1?

A33. The adjustments in columns (g) through (i) show the inflation adjustment to convert the historical test period O&M expenditures to the projected test period dollars. The inflation rates for all DO exhibits are supported by Company witness Uzenski.

Q34. What are the adjustments in column (j) of Exhibit A-13, Schedule C5.6, page 1?

A34. These adjustments are one-time known and measurable adjustments to the Distribution Expenses. The adjustment to Line No. 3, Operation Supervision and Engineering, shows a $1.6M increase related to the Damage Prevention Program. The adjustment to Line No. 11, Miscellaneous Expenses, shows the cost for the Peaker Study, $0.3 million, that the Company agreed to complete in the IRP settlement. The adjustment to Line No. 19, Maintenance of Overhead Lines – Tree

Trim, shows the $3.4 million increase in Tree Trim base O&M to remain in line with the funding levels outlined in the Tree Trim Surge plan. The adjustment in line No. 20, Maintenance of Overhead Lines – Other, shows a reduction due to Tree Trim Surge reduction of $8.8 million offset by inspection expenditures of the Pole and Pole Top Maintenance and Modernization (Pole/PTMM) program and the 4.8kV Hardening Program, an increase of $5.0 million, a net decrease of $3.8 million. The Pole/PTMM program are discussed by Company witness Elliott Andahazy. The adjustment to Line No. 12 is an adjustment to the ADMS regulatory asset supported by Company witness Uzenski.

Q35. How did the Company calculate restoration O&M expense for the projected period?

A35. As shown on Exhibit A-13, Schedule C5.6, page 2, line 22, column (h), the Company shows projected restoration expenses, including inflation, of $128.2 million. A five-year average method was used to normalize restoration expenses and is consistent with the methodology used in the Company's previous rate cases and the Commission guidance in Case No. U-21297. This method addresses the variability in these expenses.

The details of this calculation are shown on Exhibit A-13, Schedule C5.6, page 2, "Restoration Expenses". Line 2 shows the actual expenses from 2018 to 2022 associated with restoration related to storm conditions. Line 10 presents the actual expenses associated with non-storm restoration. Lines 3 and 11 include inflation adjustments for the historical expenses, and these adjustments are included on lines 4 and 12 for storm and non-storm costs respectively. The expenses for the 2018 to

2022 period are averaged in column (g) and inflation is applied to those amounts to determine the values in column (j). Column (h) shows the expenses included in the historical test period adjusted for inflation. Column (j) shows the difference between columns (h) and (i). Lines 17 to 22 summarize the calculations and shows on line 22 the $128.2 million five-year average (column (h)), the $131.1 million (column (i)) included in the historical test period and the difference of ($2.9) million (column (j)), which is the adjustment needed in the projected test period for restoration costs in this case. The pre-inflation adjustment of ($2.6) million included in column (j), line 18 is carried to page 1 of Exhibit A-13, Schedule C5.6 in column (e), line 20.

Q36. How was the projected O&M expense amount in column (l) of Exhibit A-13, Schedule C5.6, page 1, derived?

A36. The 12-month historical test year period ended December 31, 2022 adjusted expenses from column (f) were adjusted by inflation and other expected changes in column (k) to derive projected O&M costs in column (l).

<u>Part IV: Distribution Grid Plan (DGP) Overview</u>

Q37. What is the role of the Distribution Grid Plan (DGP) in supporting the grid investments included in this case?

A37. Consistent with Commission guidance on the need for shorter-term investments and longer-term grid planning, the Company filed the updated DGP on September 29, 2023, in Case No. U-20147. The 2023 DGP built on the previous DGP filed in September of 2021, also Case No. U-20147 and included an update to DTE Electric's distribution investment strategy considering factors including the continued frequency and intensity of storms, and the aging grid assets. The 2023 DGP includes an increased focus on investments that will be able to quickly deliver for customers a safer, more reliable, and more storm resilient grid over the next 5 years. In addition, the updated DGP maintains its focus on the Company's 10 to 15-year vision for the grid that includes capacity needed for electrification, and advances in technology to support both reliability and incorporation of Distributed Generation (DG)/Distributed Storage (DS). The DGP supports the development of the investments that are the basis of this case. Furthermore, the direct alignment between the DGP and the investments proposed for rate base treatment illustrate the Company's long-term plans and larger strategy for improving the strength of the distribution system.

Q38. Has the Company used previous versions of the DGP to support the development of investment plans in previous rate cases?

A38. In two of the Company's recent rate cases (MPSC Case Nos. U-20836, and U-21297), the Company referenced the 2021 DGP filed in September of 2021. In this case the 2023 DGP, along with submitted testimony, supports the Company's distribution investments. The 2023 DGP is included as Exhibit A-23 Schedule M8. The Company's investments as reflected in this case, and in previous cases, are based on long-term distribution planning processes that identify customer and grid needs and develop and prioritize projects that provide both benefits to customers in terms of improved safety and reliability in the near term (primarily achieved through Pole Top Maintenance and Modernization, Automation, and 4.8kV Hardening), and provide the foundation for long-term changes, including increased electrification and Distributed Energy Resource (DER) adoption. The investments in this case are consistent with the long-term vision laid out in the DGP filed in September 2023.

Q39. What was the Company's approach to developing the 2023 DGP?

A39. To create the 2023 DGP, DTE Electric followed the five-step methodology used in the development of the 2021 DGP:

- **Define DTE Objectives**: Reviewed objectives from the Company's previous 2021 DGP and aligned them to the long-term distribution grid vision
- **Assess Future Drivers of Change**: The future drivers of change that are expected to have a significant impact on the distribution grid over the next five to fifteen years were reviewed, including previously identified scenario signposts.
- **Assess Current State**: Assessed the current grid and its capabilities to determine how well it can support current and future customer demands.
- **Determine Gaps to Future State**: Identified future state objectives based on future drivers of change, current state assessments and distribution grid gaps.
- **Develop Investment Plan**: Based on those gaps, a five-year investment plan was developed, organized within the four pillars of investment. Individual program and project prioritization within the investment plan is done through the Company's Global Prioritization Model (GPM) process – discussed below.

Additionally, customer and stakeholder feedback were integrated into the Plan, including a shift to consider environmental justice (EJ) in DTE Electric's investment decisions so that projects benefiting our most vulnerable customers are considered in the investment prioritization process.

Q40. How did the Company gather feedback for the most recent DGP?

A40. Feedback was received in several ways including:

- The March 2023 and August 2023 4.8kV Hardening and DGP Tech Conferences which offered numerous stakeholders an opportunity to provide feedback via roundtable discussions, questions, and written comments.
- Through the regulatory process associated with Case U-21297, the company received comments and feedback through MPSC Staff and stakeholder testimony.
- The Commission issued Order and stakeholder comments received in Case No. U-20147 containing feedback on the 2021 DGP.
- Regular engagement with the Company's customers via community meetings, the DTE customer call center, MPSC complaint response, and other miscellaneous forums.

Q41. Please describe how scenario planning informs DGP investments.

A41. Grid modernization plausible scenario planning involves developing scenarios that are directionally correct and plausible. In the context of grid planning, plausible is preferable to using the most likely scenario, in order to analyze impacts that will stress or cause impacts to the grid, and therefore should be reasonably planned for. Plausible scenarios provide input to grid impact of potential future challenges, as opposed to probabilistic or forecasted scenarios. These scenarios focus on a discrete set of drivers and allow for a better understanding of the resulting grid impacts, as well as the potential for overlapping impacts on needed capabilities and the resulting determination of investments. The Company built on the work initially done in the 2021 DGP, to update three scenarios to use for identifying (1) changes coming to the grid in the future, (2) the grid impacts of those potential changes, and (3) the investments needed to mitigate grid impacts. The three plausible future scenarios selected were the Electrification scenario, the Increasing CAT storm scenario, and the DG/DS Scenario (distributed generation [DG] solar photovoltaic [PV] and distributed storage [DS]).

Q42. Can you please summarize the key highlights of the DGP?

A42. Using the learnings from scenario planning, combined with an assessment of the current state of the grid, the Company identified gaps between the existing grid and the future state required to meet the DGP objectives.

Based on this analysis, the 2023 DGP, in line with the 2021 DGP, remains focused on closing these gaps through four investment pillars supporting grid improvement:

1) <u>Tree Trimming</u> remains focused on completing the Surge plan and returning our electric grid to a routine, maintenance cycle.

2) <u>Infrastructure Resilience and Hardening</u> projects and programs focus on making the grid more resilient in the face of increasingly severe storms, replacing aging infrastructure at risk of failure, hardening the system, and

addressing areas of the system with known poor customer reliability. These projects and programs specifically target equipment with known risks, (e.g.., failed inspections or multiple prior failures), or in areas with known poor customer reliability and potential safety issues, (e.g., high SAIDI or arc wire on the system). Projects in this pillar are designed to provide improved customer reliability and replace at risk equipment quickly. Key areas of focus in this pillar are an expansion in the PTMM program to stabilize the aging overhead equipment as well as finishing the 4.8kV Hardening program which will conclude in 2026 once arc wire is removed. Infrastructure Resilience and Hardening investments are supported by witness Elliott Andahazy.

3) <u>Infrastructure Redesign and Modernization</u> projects and programs make fundamental improvements to the electrical system, including the conversion of the 4.8kV system and upgrades of the fundamental subtransmission system. Overall redesign and modernization of the system also brings reliability and resilience improvements through the replacement of aging infrastructure. Investments in this pillar provide benefits such as load relief (including increased capacity for electrification) and increased system operability. This pillar focuses on 4.8kV Conversion to rebuild the oldest sections of the grid in orders to accommodate future load growth and boost reliability. The 4.8kV Conversion projects will convert the 4.8kV system to a higher voltage and be built to the latest, most resilient standards, provide higher capacity for electrification, enable DER penetration, and improve safety by eliminating the ungrounded delta configuration and removing arc wire from the city of Detroit. More detail on the 4.8kV conversion is provided is provided in Exhibit A-23

Schedule M8 DGP. This pillar also includes subtransmission improvements to add capacity and improve performance of this fundamental part of the grid. Infrastructure Redesign and Modernization investments are supported by witness Deol.

4) <u>Technology and Automation</u> projects and programs are focused on ramping up the Company's automation capability and operational Technology (OT) investments that will enable the Company to monitor, control, and optimize the operation of grid. Investments in this pillar focus on the physical infrastructure needed to support a modern distribution grid including reclosers, capacitors and voltage regulation, and grid telecommunications as well as the software and technology needed for operations and improved customer communication. Advanced technology and automation on the grid not only improve customer reliability but is also a key factor in enabling customer accessibility to the grid. Additional investments include the electric system operation center (ESOC) and advanced distribution monitoring system (ADMS), and develop more advanced analytic capabilities. This pillar is an integral part of grid modernization and will allow the Company to develop needed capabilities in grid observability, analytics and computing, gird controls, and communications. Investments in Technology and Automation are supported by witnesses Hartwick and Steudle.

Q43. When will the Company file a new DGP?

A43. The Company expects to file another Distribution Grid Plan in 2025 on the normal 2-year schedule.

Line No.

Part V: Strategic Capital Overview

Q44. How does the Company categorize capital investments?

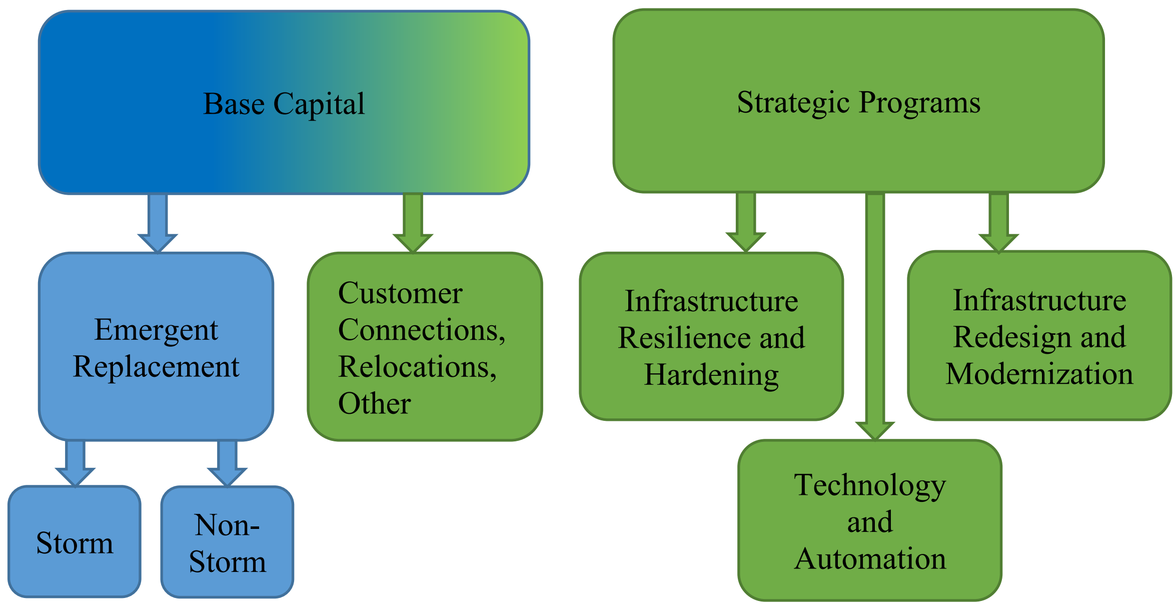
A44. Capital investments are broken out into two primary categories: Base Capital and Strategic Capital. Base Capital programs include work the Company is required to perform as part of normal business activities. There are two sub-categories of Base Capital: (1) Emergent Replacements and (2) Customer Connections, Relocations & Other. Emergent Replacements include expenditures to recover from interruptions in electric service (e.g., emergent replacements during storms, equipment failures at substations), address immediate safety concerns, or return the system to normal operating conditions, and are reactive in nature. Customer Connections, Relocations and Other are planned capital expenditures to address customer requests for new or upgraded service connections, or to relocate equipment in response to third-party requests (e.g., Michigan Department of Transportation [MDOT]). Details for Base Capital programs are included in Exhibit A-12, Schedule B5.4, pages 3 to 12, and in more detail on Exhibit A-23, Schedule M4, and are supported by witness Hill.

The second primary category of capital is Strategic Capital. Strategic Capital projects and programs include work the Company performs to improve safety, reliability and operability, and grid automation and modernization. These investments are subcategorized into three areas or investment pillars: Infrastructure Resilience and Hardening, Infrastructure Redesign and Modernization, and Technology and Automation. Details for Strategic Capital programs are included in Exhibit A-12, Schedule B5.4, pages 13 to 18, and in more detail in Exhibit A-

Line No.

23, Schedules M4 through M7, and are supported by witnesses Hill, Elliott Andahazy, Hartwick, and Deol.

Figure 8 Categories of Planned and Unplanned Capital Investment



*green coloring represents planned capital categories

Q45. Which categories of Capital Investment is the Company able to plan for ahead of time?

A45. In **Figure 8**, the green capital categories are planned: strategic programs and customer connections, relocations and other. The only category of capital for which the Company cannot fully plan is emergent replacements, depicted in blue.

Q46. What level of investment is the Company requesting for capital investments that are for strategic programs or projects in the forward-looking test year ending December 31, 2025?

A46. In the projected test year ending December 31, 2025, the Company is proposing to invest a total of $827.3 million in strategic programs and projects as part of this case (Exhibit A-12 Schedule B5.4 Page 1, Line 22). Additionally, the Commission approved a Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM) in Case No. U-21297 totaling an additional $290.1 million in 2025 that is not included in the Company's rate request in this case (Exhibit A-33 Schedule X1 Page 1, Line 8) - Witness Foley provides additional information on the IRM in his testimony. Summing both the proposed strategic investment for the 2025 test year and the 2025 IRM yields a total of $1,117 million of 2025 strategic investment.

Q47. What are emergent replacements, and what level of investment is the Company requesting for emergent replacements in the test year?

A47. Emergent replacements are those necessitated by damage or failure on the system. Although investments in this category are reactive, rather than proactive, they are essential to restoring customers' power after an outage event, maintain system operability, and in many cases increase reliability. For the projected test year ending December 31, 2025, the Company forecasts $506.9 million in emergent capital (Exhibit A-12 Schedule B5.4 Page 1, Line 7). Witness Hill discusses emergent replacements in detail in his testimony.

Q48. What type of work comprises Customer Connections, Relocations and Other, and what level of investment is the Company requesting for Customer Connections, Relocations and Other in the test year?

A48. The Customer Connections, Relocations and Other category includes multiple investment areas:

- Connections and New Load is work required to connect new customer sites and load to the distribution system
- Relocations is work required to move DTE Electric infrastructure primarily driven by MDOT and local road commission projects
- Electric System Equipment is an inventory of critical spare equipment to support emergent replacements and planned projects
- Normal Retirement Unit Change-out (NRUC) and Improvement Blankets is work focused on reducing customer outages, replacing end-of-life equipment and supporting the AMI platform and data
- General Plant, Tools & Equipment and Miscellaneous are new replacement tools required for field workers to perform their tasks, engineering test equipment and substation physical security
- Public Lighting Department Project is a project to convert Public Lighting Department customers to the Company's distribution system

The Company is requesting $301 million in Customer Connections, Relocations and Other (Exhibit A-12 Schedule B5.4 Page 1, Lines 15 and 16). Witness Hill discusses the Customer Connections, Relocations and Other category in detail in his testimony.

Part VI Capital Exhibits Description

Q49. How will the Company support the capital investments it is requesting in this case?

A49. The Company is supporting the requested capital investments using witness testimony as well as five capital investment exhibits:

- Exhibit A-12 Schedule B5.4 Projected Capital Expenditures – Distribution Plan (witnesses Hill, Elliott Andahazy, Deol, Hartwick and Steudle).
- Exhibit A-23 Schedule M4 Distribution Plant Capital Project Detail – Base Capital (witness Hill).
- Exhibit A-23 Schedule M5 Distribution Plant Capital Project Detail – Infrastructure Resilience and Hardening (witness Elliott Andahazy and Hill).
- Exhibit A-23 Schedule M6 Distribution Plant Capital Project Detail – Infrastructure Redesign and Modernization (witness Deol).
- Exhibit A-23 Schedule M7 Distribution Plant Capital Project Detail – Technology and Automation (witnesses Hartwick and Steudle).

Q50. What information is included in Exhibit A-12 Schedule B5.4?

A50. Exhibit A-12 Schedule B5.4 includes the total capital forecast for all of Distribution Operations categories from the historical test period, 2022, through the projected test year 12-months ending December 31, 2025, excluding investments that will be recovered through the Commission approved IRM for the 13 months ending December 31, 2024 and 12 months ending December 31, 2025. Witness Foley covers the IRM in his testimony.

Page 1 of Exhibit A-12 Schedule B5.4, column (a) includes a brief description of the expenditures included on the line, and column (b) includes the historical (2022) actual investment for each category. Between columns (a) and (b) is a list of footnotes that reference additional details for the investment and forecasting methodologies and witnesses supporting each category. Columns (c) to (e) include forecasts for each line item for 2023, 2024, and the 24-month period ending

December 31, 2024, respectively, while column (f) includes forecasts for the 12-month period ending December 31, 2025, the projected test year.

Page 2 of Exhibit A-12 Schedule B5.4 provides additional detail on the information provided on page 1, showing the normalization adjustments used to reconcile the historical 12 months ended December 31, 2022 to the projected calendar years of 2023, 2024 and 2025. Page 2 is structured in much the same way as page 1 with the following exceptions: columns (c) and (d) include adjustments to normalize emergent replacement capital to the five-year average for use in 2024 and 2025 forecasts, and columns (e) to (g) provide forecasted investment for 2023, 2024 and 2025 respectively.

Page 3 of Exhibit A-12 Schedule B5.4 provides the calculations of the normalization adjustment applied to emergent capital to reflect a historical five-year average for forecasting less the emergent reduction due to strategic investment and surge tree trim reduction on line 29. More detail on emergent capital expenditures is provided by witness Hill, further detail on the emergent reduction due to strategic investment is discussed in Part IX Capital/Reliability Model and more detail regarding the surge tree trim reduction is sponsored by Witness Steudle.

Pages 4 through 9 of Exhibit A-12 Schedule B5.4 provide the three-year historical average and projected investments for the Customer Connections, Relocations, and Other subcategories. More detail on these capital expenditures is provided by witness Hill.

Pages 10 through 12 provide project lists for the historic test period for New Business and Relocations and are supported by witness Hill.

Pages 13 through 18 provide the same information as pages 1 and 2 for all the strategic capital projects by category and are supported by various DO witnesses as shown on these pages.

Page 19 provides detail on the Allowance for Funds Used During Construction (AFUDC) for DO projects and is supported by witnesses Hill, Elliott Andahazy, Deol, and Hartwick. Capital investments include an AFUDC for eligible projects that are in Construction Work in Progress (CWIP) as described by Witness Uzenski. The total DO-related AFUDC is projected to be $13.8 million for the 12-month period ending December 31. 2025. The authorized overall rate of return used was 5.561% per the Order in Case No. U-21297.

Pages 20 through 26, supported by witnesses Hill, Elliott Andahazy, Deol, Steudle, and Hartwick, provide a breakdown of plant activities, which are used by witness Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the projected balance sheet. Column (a) lists the project and program descriptions listed in the earlier emergent, the customer connections, relocations, and other strategic capital pages. Column (b) includes a corresponding in-service assumption: “Annual” indicates plant investment is generally unitized within the year of investment, while a specific in-service date is used for projects that remain in CWIP for more than a year before moving into Plant in Service. Capital expenditures consistent with page 1 are summarized in columns (c) through (f). Column (g) includes an estimated percentage of removal costs included within the capital expenditures. Removal costs, as discussed by witness Uzenski, are charged to accumulated depreciation rather than Plant/ CWIP and are therefore not depreciable. Removal cost of 15% based on historical trend of removals as a component of capital expenditures is applied to Base Capital Programs, Infrastructure Resilience and Hardening, and Infrastructure Redesign. Technology and Automation projects are assigned 0% since there is no related removal work. Columns (h) through (j) reflect calculated removal costs based on projected Capital Expenditures in columns (d) through (f) multiplied by the removal cost percentage in column (g). The remaining capital expenditures will appear in Plant in Service columns (k) through (m) if the in-service assumption is "Annual", or CWIP columns (n) through (p) until the date of in-service as indicated in column (b). At the time of in-service (as indicated in column (b)), cumulative investment including the historical period is transferred from CWIP to in-service (excluding the removal cost estimate).

Q51. Can you describe what is included in the Exhibit A-23 Schedules M4-M7?

A51. Yes. Exhibit A-23, Schedules M4-M7, supported by witnesses Hill, Elliot Andahazy, Deol, Hartwick and Steudle, provide greater project detail for all projects and programs included in Exhibit A-12, Schedule B5.4, and represents 100% of the Company's total forecast capital for DO. Each document, which can be from one to several pages, includes the following:

- Program: As described in Exhibit A-12, Schedule B5.4, pages 3 to 18 column (a).
- Purpose and Necessity: A description of the driving forces for the work.

Line No.

- Category: The pillar of Strategic Capital investment from the DGP or the Base Capital investment.
- Line Number: A reference to the exhibits, schedule, page, and line numbers supported.
- Scope: The scope of work.
- Benefits: How the Company's customers benefit from the program and a description of the how the project or program is expected to impact operations and reliability.
- Impact Dimensions: The GPM dimensions the strategic capital project or program will impact. Base capital is excluded from GPM scoring.
- Approximate Construction Schedule: Proposed work schedule for the rate case period.
- Budget Basis: Origin of budget estimate.
- Total Estimated Cost: The total expected cost of the project in present dollars – this field was added per direction from the Commission (Case No. U-21297, p108).
- Projected: The expected cost of the program for the forecasted years 2023, 2024, and 2025 in current dollar values.

Q52. What is included in the "Other Cost" line item shown in Exhibit A-23 Schedules M4-M7?

A52. The other cost line item represents the forecasted amount of overheads that get applied to a given project/program. Examples of project or program overheads include facilities, stock, and procurement. Facilities overhead represents the costs related to preventative maintenance, repairs, and improvements to facilities; these costs are allocated to capital projects based on the amount of direct labor. Stock overhead represents the costs related to operation of warehouses; these costs are allocated to capital projects based on their stock and material purchases. Procurement overhead is the cost related to the supply chain procurement process; these costs are allocated based on the project stock and material purchases, contractor expenditures, and consultant expenditures.

"Other" costs are allocated to projects based on the mix of direct costs such as labor, material usage, contractor expenditures, etc. "Other" costs for each project/program can vary year to year based on the mix of direct costs. If a project has material purchases scheduled for year one and the labor to install scheduled for year two, it could see more overheads associated with Stock and Procurement for the first year and overheads associated with Facilities in the second year. As the mix of direct costs change year over year, the other costs associated will change as well.

Part VII: Capital Investment Variance Discussion

Q53. What is the purpose of the variance analysis section of your testimony?

A53. To describe variances from forecast in calendar years 2022-2024. The reasonableness and prudence of these expenditures is supported primarily by witnesses Hill, Elliot Andahazy, Hartwick, Deol, and Steudle in their respective testimonies.

2022 U-21297 Forecast vs. U-21534 Actuals

Q54. How does the Company's 2022 forecast in Case No. U-21297 compare to the actual capital investment for 2022?

A54. Exhibit A-23 Schedule M1 compares the 2022 actual capital investment to the Company's capital forecast from Case No. U-21297. Overall, the Company invested $56.6 million more than forecasted in Case No. U-21297 for calendar year 2022, or approximately 4% above the original forecast (Exhibit A-23, Schedule M1, page 1, line 25). The difference is driven by lower than projected base capital of $13.2 million and increased investments in strategic capital of $69.8 million. Exhibit A-23 Schedule M1, U-21297 vs. U-25134 2023 Forecast Comparison, provides the project level detail of the variance.

Q55. What are the main drivers of the decreased investment in base capital in 2022?

A55. In 2022, the actual investment was $2.8 million lower than forecast in Emergent Replacements (Exhibit A-23, Schedule M1, page 1, column c, line 7) and $10.4 million lower than forecast in Customer Connections, Relocations and Other (Exhibit A-23, Schedule M1, page 1, column c, line 15) and Customer Advances for Construction (Exhibit A-23, Schedule M1, page 1, column c, line 16). Lower investment in Emergent Replacements were driven by lower than forecast equipment failure events. The lower investment in Customer Connections, Relocations and Other and Customer Advances for Construction was driven by a lower volume in the number of customer requests.

Q56. What are the main drivers of the increased strategic investment in 2022?

A56. In 2022, $34.3 million of increased investment was in the Infrastructure Resilience and Hardening Pillar. The Company was able to complete more units than forecasted in the Pole and Pole Top Maintenance and Modernization program with $13.7 million of additional investment and $6.2 million of additional investment in the 4.8kV Hardening program. Similarly, the Company increased its investment by $4.5 million in the Frequent Outage Program (CEMI) program by both addressing more circuits and increasing scope on circuits where more work was needed for reliability improvements.

The Infrastructure Redesign and Modernization Pillar had an increased investment of $10.3 million primarily driven by accelerating tree trimming work on CODI: Islandview Substation ahead of circuit conversion work as well as progress payments for long lead substation equipment for the 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) and System Loading: Richmond/Armada.

The Technology and Automation Pillar had increased investment of $25.2 million. The Work Management and Scheduling Upgrades project had additional investment of $6.0 million for new tools supporting field and storm processes. For the Grid Automation Telecommunications as well as NWA: Omega Load Relief, both projects pulled ahead $4.4 million of material and equipment purchases to avoid supply chain delays. The "Other Modernize Grid Management project" had an additional $3.0 million in investment driven by Error Free Communications interface work and field network end of life equipment replacement. For the Tree Trim Risk Prioritization Model, the total investment was shown in Exhibit A-12, Schedule B5.7.7, page 1, line 25 in Case No. U-21297. When the project was implemented, the investment was split into two locations in this case. The $6.4 IT investment shows on Exhibit A-12, Schedule B5.7.7, page 1, line 39 and $3.1 million of investment shows on Exhibit A-12, Schedule B5.4, page 17, line 24. This split results in a $3.1 million increase investment in the Technology and

Automation Pillar. For the Interconnection Process Enablement project, the interconnection gateway platform development was pulled ahead leading to $2.8 million of increased investment. An additional $5.9 million of investment was made across other projects as shown in exhibit A-23, schedule M1.

These expenditures facilitated necessary system upgrades or improvements to continue safe and reliable service to customers and were reasonably and prudently incurred.

Q57. How did actual capital investments for 2022 compare to rates included in the Commission's final Order for Case No. U-21297?

A57. Distribution Operations' actual capital investments equaled $1,496.1 million in 2022. In the rate order, distribution plant investments of $1,434.3 million were included in rate base, or $61.8 million less than the actual prudently incurred investments (see witness Uzenski's Exhibit A-12, Schedule B5, line 7).

<u>2023 U-21297 Forecast vs. U-21534 Forecast</u>

Q58. How does the Company's 2023 forecast in MPSC Case No. U-21297 compare to the forecast in this case?

A58. Exhibit A-23 Schedule M2 compares the 2023 forecast capital investment Case No. U-21297 to this case. Overall, the Company is projecting to invest $129.4 million more than forecasted in Case No. U-21297 for calendar year 2023, approximately 9% above the original forecast. The difference is driven by higher than projected base capital of $139.9 million and lower strategic capital investments of $10.5

million. Exhibit A-23 Schedule M2, U-21297 vs. U-25134 2023 Forecast Comparison, provides the project level detail of the variance.

Q59. What are the main drivers for the 2023 base capital forecast changes?

A59. The primary changes in the 2023 base capital forecast changes are driven by storms. 2023 included five (5) catastrophic storms, including the most damaging winter ice storm in Company history, and another summer catastrophic storm event that included heavy damage from historic six tornadoes. See witness Hill's testimony for discussion on base capital.

Q60. What are the main drivers for the 2023 strategic capital forecast changes?

A60. For 2023, the Company is projecting $42.4 million of increased investment in the Infrastructure Resilience and Hardening Pillar, $29.0 million of increased investment in the Technology and Automation Pillar, and $81.9 million of decreased investment in the Infrastructure Redesign and Modernization Pillar. Overall, the Company is forecasting $10.5 million of decreased investment in strategic capital.

<u>2024 U-21297 Forecast vs. U-21534 Forecast</u>

Q61. How does the Company's 2024 forecast in MPSC Case No. U-21297 compare to the forecast in this case?

A61. Exhibit A-23 Schedule M3 compares the 2024 forecast capital investment Case No. U-21297 to this case. Overall, the Company is projecting to invest $59.8 million less than forecasted in Case No. U-21297 for calendar year 2024, or approximately 4% less the original forecast. The difference is driven by higher than projected base capital of $111.0 million and lower strategic capital investments of $170.8 million. Exhibit A-23 Schedule M3, U-21297 vs. U-25134 2024 Forecast Comparison, provides the project level detail of the variance.

Q62. What are the main drivers for the 2024 base capital forecast changes?

A62. Emergent replacements are forecast based upon a five-year historical average as discussed in Witness Hill's testimony. In this case, per the approved methodology, the five-year average calculation replaced 2017, a lower cost year, with 2022, a higher cost year. This change increased the projection, resulting in an additional $69.2 million in the 2024 forecast for emergent replacement (Exhibit A-23, Schedule M3, column d, line 7). This increase in Emergent Replacement did not impact the Company's strategic capital investment level. For Customer Connections, Relocations and Other, the I-375 relocation project is a primary driver of increased investment with $25 million projected in 2024. The other cost drivers that make up the full $111.0 million are found in Exhibit A-23 Schedule M3, U-21297 vs. U-25134 2024 Forecast Comparison.

Q63. What are the main drivers for the 2024 strategic capital forecast changes?

A63. In Case No. U-21297 the Company forecasted total strategic capital at $879.6 million for the calendar year 2024. In this case the Company is forecasting a total strategic capital investment of $708.8 million, a decrease of $170.8 million from the U-21297 forecast. Of the $170.8 million decrease, $60.6 million is a simple shift of investment to the IRM. Project and Program investment changes were based on the Company's review of strategic factors since the initial Case No. U-21297 filling including 2023 ice storm learnings (increased focus on near term reliability such as 4.8kV Hardening, and Automation) and the December Case No. U-21297 rate order. The Commission approved an annual investment level of $659.4 million in strategic investment in the Case No. U-21297 order, a difference of $220.1 million from what the Company originally forecasted.

In the Infrastructure Resilience and Hardening Pillar, the Company is forecasting an increase of $56.6 million, primarily driven by an $80.0 million increase in the 4.8kV Hardening program, carryover work for Substation Risk: McGraw of $37.8 million, an offsetting decrease of $57.1 million in PTMM due to rate order guidance, and other miscellaneous adjustments that result in an additional $4.1M reduction. The Company is forecasting an increased investment of $24.4 million in the Technology and Automation Pillar for operational technology projects initiated to support and enhance storm restoration efforts. In the Redesign and Modernization Pillar, the Company is forecasting a decrease of $251.7 driven by shifting $60.6 million of investments to the IRM and $191.2 million of project investment to later years, in part, to shift investment to projects that impact near term system resiliency, including Automation and Hardening.

Capability to Execute Strategic Work

Q64. How does the Company ensure that it has the capabilities and resources required to make its proposed strategic investments?

A64. As the long-term needs of the electric grid call for increasing levels of investment, the Company has responded by increasing our labor force (employees and contractors, engineering and planning staff), leveraging partnerships, and strengthening project management and supply chain oversight. The Company has instituted workforce planning processes and tools that calculate overall resource demands for all field trades, as well as support and enabling groups including engineering, designers, and project managers. Estimates and forecasts for short-term and long-term resource needs are performed on an ongoing basis as an input to our sourcing decisions. DTE Electric will add staffing as needed to address our growing capital investment portfolio.

The projected resources (Company and contractors) required by year-end 2023 to complete the planned strategic capital investments is just over 5,200 full-time equivalents (FTEs). The projected resources (Company and contractors) required by year-end 2024 to complete the planned strategic capital investments is approximately 5,500 FTEs. As a result, the Company currently has more line workers in the field than ever before. Additionally, the Company utilizes strategic partnerships with engineering and design firms and front-line labor contractors. Local contractor workforce has been growing as our investments have increased. Contractor needs that exceed the local workforce availability and are supplemented with additional work force from outside of the area.

As discussed above, the Company has a Project Management Organization (PMO) specifically focused on managing this growing work force. Additionally, the PMO works with the Company Supply Chain Management team to mitigate impacts of material supply chain challenges. These mitigation actions include, but are not limited to:

1) Increasing the number of suppliers for key equipment including transformers, insulators, and cross arms.
2) Demand planning with a long-time horizon, including securing product slots for current year and beyond with suppliers.
3) Deploying weekly and daily tracking calls with key suppliers (driving collaboration and leveraging our resources, including transportation, to keep orders on track).
4) Sending supply chain and other employees to supplier facilities to provide real time governance and quality control on purchased materials.

The Company continues to grow its strategic capital capabilities with over $700 million invested in 2022 and over $800M invested in 2023.

Part VIII: Global Prioritization Model

Q65. What is the Global Prioritization Model (GPM) and how does it support the prioritization of capital strategic investments?

A65. The GPM is a tool the Company's Distribution Operations team developed to prioritize investments by ranking projects and programs based on the benefits the project or program delivers for a given level of investment. The ranking is accomplished through a process of evaluating a project across ten impact dimensions, which represent project benefits, and developing a total project score based on the weighting of each impact dimensions. The model results serve as the initial basis for the Company's investment prioritization and highlight those projects that have the highest relative benefit and/or are most urgent.

Line No.

Q66. Does the GPM consider benefits and costs?

A66. Yes. Each of the ten impact dimensions within the GPM measures a benefit of the project or program. These benefits are weighed against costs in eight of the dimensions. Costs are not considered when evaluating if the project or program delivers benefits in the “Regulatory Compliance” or “Investment in EJ communities” dimensions.

Q67. Does the GPM determine if benefits exceed costs?

A67. No. In order to determine if benefits exceed costs, all benefits would need to be translated into a monetary value. Only two of the benefits the GPM captures, O&M Avoidance and Capital Avoidance, are measured in monetary terms. All other dimensions are quantified in non-monetary terms. While the GPM does not determine if benefits exceed costs, it does utilize benefit-cost ratios in most of its dimensions to provide a result where projects which deliver the most benefits per dollar invested receive the highest scores. Not all dimensions use this structure, specifically “Regulatory Compliance” and “Investment in EJ Communities”, where programs receive a score without dividing by overall project cost.

Q68. Why doesn’t the Company convert all project benefits to a monetary value?

A68. The non-monetary benefits which the GPM measures have no standard or generally accepted method available to convert the quantified benefits into a monetary value. While SAIDI and SAIFI can be monetized relative to the customer potential cost impacts of an outage by using the ICE calculator developed by Lawrence Berkeley National Laboratory (LBNL), that methodology has limitations including dated customer survey data. Other benefits such as providing load relief so that equipment does not operate over its designed rating, or reducing the probability of major events, or investing in EJ communities do not have any commonly accepted conversion to a monetary value. Additionally, the Company does not place a monetary value on project benefits which deliver safety benefits such as a reduction in energized wiredowns. Using the Current GPM methodology, the Company can transparently demonstrate which projects provide the highest benefit for customers across different impact dimensions.

Q69. What determines whether a project is scored in the GPM?

A69. The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization.

Q70. Has the GPM model been recently updated?

A70. Yes. As introduced in the 2023 DGP filing the GPM has been updated to include three new dimensions to capture additional project benefits and to align to two additional planning objectives (Clean, and Customer Accessibility and Community Focus). Specifically, the dimension of "Investment in EJ communities" was added based on feedback from the Commission to incorporate equity into the decision-making process.[4] Additionally, the weightings of each dimension have been updated. The "Investment in EJ communities" addresses the Commission's order in Case No. U-20836: "the Commission will continue to hold DTE Electric to its

[4] See Commission's Order on November 18, 2022 in docket U-20836 (p 459).

commitments to more fully incorporate equity considerations into its decision-making processes".

Q71. How does the GPM consider DTE Electric's planning objectives when evaluating the Company's distribution investment options?

A71. The Company uses the GPM to assess the benefits that strategic investments have on the distribution system as they relate to each of five planning objectives of 1) Safe, 2) Reliable and Resilient, 3) Affordable, 4) Clean, and 5) Customer Accessibility and Community Focus. All impact dimensions that are measured in the GPM are aligned to one or more of these five planning objectives as described in **Table 6**. These five objectives also align with the Commission's overarching objectives for the electric distribution system, which are safety, reliability and resilience, cost effectiveness and affordability, and accessibility.[5]

Table 6 Mapping of GPM impact dimensions to Planning Objectives

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimensions	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Regulatory Compliance	✓	✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	Investment in EJ communities					✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		

[5] See Commission's Order on October 11, 2017 in docket U-18014 (pp10-12) and re-affirmed in the Commission Order on August 20, 2020 in docket U-20147 (pp 36-38).

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Q72. What impact dimensions are quantitatively assessed to determine project and program impact across the Company's Planning Objectives?

A72. In the GPM, strategic investments are evaluated against ten impact dimensions as described in **Table 7**. Quantitative assessments are conducted for all the impact dimensions to score and rank investments.

Q73. What impact dimensions have remained unchanged in the updated GPM?

A73. Six of the Seven original impact dimension have calculations that remain unchanged. Four impact dimensions, Regulatory Compliance, Major event risk, O&M Avoidance, and Capital Avoidance, are unchanged from the previous GPM. Two additional dimensions have been renamed but the calculations are the same as in the previous GPM. The "Reduce electrical hazards" dimension was previously named "Safety" and "SAIDI" was previously named "Reliability".

Q74. What impact dimensions were added or changed in the updated version of the GPM?

A74. Two dimensions were added, and one dimension was divided into two separate dimensions. The two new dimensions are "SAIFI" and "Investment in EJ communities". To better differentiate day-to-day loading challenges from constraints that limit operational flexibility, the "Load Relief" dimension in the previous iteration of the GPM has been split into two dimensions: "Overload Relief" and "Capacity Relief".

Q75. Was the weighting of dimensions changed in the updated version of the GPM?

A75. Yes, the weighting of the dimensions was simplified from a ten-point scale to a three-point scale.

Table 7 Global Prioritization Model Impact Dimensions

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	
Overload Relief	• Elimination of overloaded equipment	3
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010, report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	2
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	1

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Q76. What are the drivers of the changes to the GPM?

A76. The GPM was changed to capture customer benefits that were not previously accounted for, and to include benefits from across all of DTE Electric's Planning Objectives (as shown in **Table 6**). "SAIFI" was added because reducing frequency of outages is important to providing reliable power to our customers, and because the State's Reliability and Service Quality standards provide guidance on what outage frequency is consistent with an acceptable level of service. Project benefits in the "Capacity Relief" dimension were added to measure projected load constraints in 2035, and to account for benefits accrued by addressing circuits that do not have enough capacity to fully realize automation capabilities. Incorporating the 2035 load projection aligns with the Company's goals to provide a grid that facilitates a transition to a decarbonized economy. "Overload Relief" accounts for benefits that come from reduced day-to-day equipment loading. Finally, by adding the "Investment in EJ communities" dimension, which scores a project based on the percentage of customers benefiting from this project who are from EJ communities, we have incorporated equity into our planning and capital prioritization process as directed by the Commission in 2022.[6]

Q77. How are projects ranked using the GPM?

A77. Strategic investments are assessed, scored, and then ranked in a quantitative manner on how they support/improve each impact dimension. **Table 8** shows the mapping of the investments to the impact dimensions they general receive a score in, based on the benefits the investment delivers.

[6] See Commission's Order on November 18, 2022 in docket U-20836 (p 459).

Table 8 Selected programs and GPM impact dimensions

Program	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Regulatory Compliance	Major Event Risk	Capacity Relief	Investment in EJ Communities	O&M Avoidance	Capital Avoidance
Substation Risk						X		*		
4.8kV Hardening	X		X	X				X	X	X
PTMM	X		X	X	X			P	X	X
Cable Replacement						X		P		X
Frequent Outage			X	X	X			P		
Breaker Replacement			X	X		X		P	X	X
URD Replacement			X	X				P		X
Subtransmission Redesign		X					X	*		
CODI	X	X	X	X		X		*	X	X
4.8kV Conversion	X	X	X	X		X		*	X	X
System Loading		X	X	X		X	X	*	X	X
Automation	X		X	X				P		

Investment in EJ Community Key: * = Dependent on location of project, X = Yes, addresses EJ communities, P = program where some areas of the program will occur in EJ communities

Detailed analyses based on historical data, engineering assessments, and field feedback was used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios used to determine the relative difference between projects.

Unit measurements used for benefit-cost ratios are different for each impact dimension. For example, reliability benefits are captured in customer minutes of interruption reduction whereas O&M and reactive capital benefits are captured in dollars avoided.

Each program's benefit-cost score for each impact dimension is indexed so that a project with a benefit-cost ratio at the 95th percentile receives a score of 100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100. This method provides three benefits. First, by aligning the 95th percentile to a score of 100, outlier projects do not skew the entire index. Second, the 100-point scale makes it makes it easy to understand which projects are delivering the highest benefit per dollar invested – namely, the ones which score closer to 100. Finally, indexing, along with the weighting of dimensions, allows for the consideration of multiple monetary and non-monetary benefits to be combined into a single analysis.

Impact dimensions are weighted relative to each other. **Table 7** lists the different weights given to each impact dimension. The weights of each dimension were simplified in the recent GPM update from a 10 point range to a 3 point range Dimensions which align with core safety and reliability improvements, such as Reduce Electric Hazards, one of the Company's most important impact dimensions, is given the highest weight of 3. This change effectively means that a score of 100 in a lower weighted dimension will not be worth as much as a 100 rating in Reduce Electrical Hazards. For example, if a project's Reduce Electrical Hazards score is 50 (on a 0-100 scale), it will be multiplied by a weighting factor of 3 to receive a score of 150. A project with a Capacity Expansion score of 50 will be multiplied by the weighting of 2 and contribute 100 to the total scoring. This example illustrates how the impact dimension weights will rank projects higher if they provide benefits in dimensions which have higher weightings. Once a program's index scores have been calculated across all impact dimensions and adjusted by weighting, the index scores are summed together to determine the program's overall score. The higher the score, the better the GPM ranking.

Q78. How do the GPM results influence the Company's distribution investment decisions?

A78. We use the GPM to pick the highest relative benefit projects that will have the greatest impact improving the grid and the overall customer experience. Projects and programs are ranked using the GPM on an annual basis. Investments that score highest in the GPM rankings are generally selected for the Company's distribution infrastructure strategic investment plan. As described in detail below, there are some projects that are chosen outside of the GPM process or lower ranked projects within the process that are funded for various operational reasons.

Projects and programs that span multiple years are evaluated every year and may experience a change in GPM ranking if additional information changes the expected project costs or benefits. However, to keep scoring relatively consistent year over year, the entire project cost and entire project benefits are still used when scoring the project or program – although the project costs and benefits will be adjusted for known changes (examples include costs increases or more benefits than forecast).

Q79. How does the GPM support reasonable and prudent prioritization of investments?

A79. The GPM helps the Company compare hundreds of vastly different types of projects and programs of different sizes and identify which ones are going to be the most beneficial for customers.

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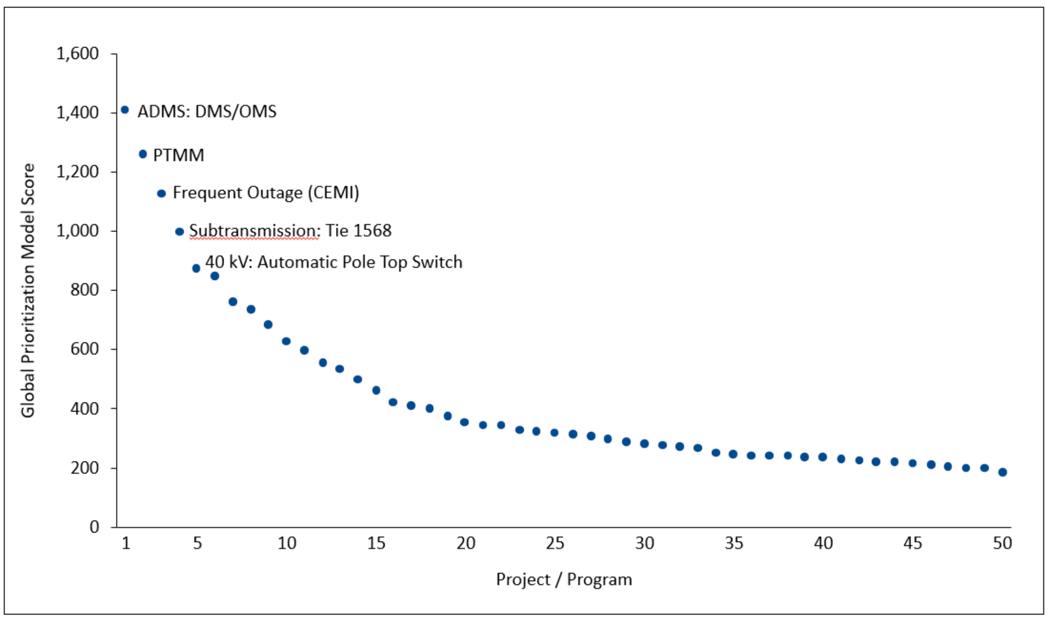
Q80. What are the GPM scores for the projects and programs proposed in this case?

A80. The total GPM scores for strategic capital projects and programs, ranked from highest to lowest, is illustrated in **Figure 9. Table 9** lists the names of the capital projects and programs ranked in the top 50. GPM scores for the top 50 projects and programs including scores for each of the 10 impact dimensions is included in Exhibit A-23 M14 GPM Project and Program Rankings. Tree trimming[7] to the enhanced specification, although excluded from the **Table 9** and **Figure 9**, continues to provide high customer benefits, and ranks within the top five projects and programs in the Company's five-year investment portfolio.

Figure 9 Overall Benefit-Cost Scores for top 50 strategic capital programs and projects



[7] Tree trimming, as an O&M program, is excluded from the **Figure 9** and **Table 9**. Nonetheless, tree trimming to the enhanced specification has a top 5 benefit-cost ranking among all programs.

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Table 9 Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/Project	Rank	Capital Program/Project
1	ADMS: DMS/OMS	26	CODI: Targeted Network Secondary Cable Replacement
2	Pole and Pole Top Maintenance and Modernization (PTMM)	27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
3	Frequent Outage Program (CEMI)	28	Substation Risk: Chestnut
4	Subtransmission Redesign & Rebuild: Tie 1568	29	Cable Replacement Program
5	40 kV: Automatic Pole Top Switch	30	Subtransmission Redesign & Rebuild: Trunk
6	4.8 kV CC: Hawthorne Relief and Circuit Conversion	31	CODI: Islandview Substation
7	4.8 kV Hardening	32	Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring
8	CODI: Charlotte Network Upgrade	33	Subtransmission Redesign & Rebuild: Bernard
9	Distribution Automation	34	CODI: Kent/Gibson Conversion
10	Subtransmission Redesign & Rebuild: Trunk 2237-ST	35	Subtransmission Redesign & Rebuild: Trunk 7386
11	CODI: Garfield Network Upgrade	36	URD Replacement Program
12	Subtransmission Redesign & Rebuild: Trunk 7105	37	Subtransmission Redesign & Rebuild: Trunk 7333
13	Substation Risk: Savage	38	CODI: Alfred Substation Expansion
14	Subtransmission Redesign & Rebuild: Trunk 7106	39	Subtransmission Redesign & Rebuild: Trunk 4217
15	4.8 kV CC: ISO Conversion Program	40	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
16	4.8 kV CC: Zenon Circuit Conversion Phase 2	41	Subtransmission Redesign & Rebuild: Trunk
17	Subtransmission Redesign & Rebuild: Trunk 2419	42	Subtransmission Redesign & Rebuild: Hurst
18	CODI: Howard Conversion	43	4.8 kV CC: Cortland / Oakman / Linwood Consolidation
19	4.8 kV CC: McKinstry Sub Decommission	44	Subtransmission Redesign & Rebuild: Tie 6907
20	Substation Risk: Port Huron	45	Subtransmission Redesign & Rebuild: Cortland Station Expansion
21	8.3 kV CC: Pontiac Overhead/Underground Conversion	46	Breaker Replacement Program
22	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	47	Substation Risk: McGraw
23	Subtransmission Redesign & Rebuild: Trunk 2255	48	4.8 kV CC: Belleville Substation and Circuit Conversion
24	4.8kV CC: Barber Substation and Circuit Conversion	49	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
25	Subtransmission Redesign & Rebuild - Trunk 2448	50	Subtransmission Redesign & Rebuild: Waterman

Q81. Are there other factors besides the GPM ranking that determine final timing of program and project selection?

A81. Yes. While the benefit-cost scores of programs and projects and their prioritization ranking provide the foundation for the Company's strategic investment decisions, there are other considerations that impact project selection and timing, as listed below:

- Investment timing for programs and projects considers the impact on workforce needs. Resources required for engineering, design, project management, scheduling, and construction need to be evaluated not only by project type (substation, overhead or underground) but also by geographic location. Resource gaps and balancing are evaluated before project sequencing decisions are made. Funding decisions also consider the Company's capacity to perform the work, as the Company often partners with third parties to plan and execute projects.
- System operational constraints and stability, occasionally including transmission, can cause the Company to pull a project ahead. For example, a project may be needed to address subtransmission system integrity caused by load growth.
- Regulatory requirements or guidance also influence the selection of some projects and programs regardless of the GPM ranking. NERC requirements, for example, require upgrades to ensure the bulk electric system is unaffected by subtransmission outages. These NERC driven projects have benefits that are difficult to quantify in GPM.
- Safety issues that cannot be easily quantified and indexed could warrant an investment outside of the GPM model to protect our customers or

employees. For instance, subtransmission disconnect switches and the Pontiac vault projects are necessary to meet operational safety needs.

- Pilot projects are excluded from the ranking process as they are used to determine what the true benefits and cost will be to complete an activity that the Company believes will be beneficial to its customers. In other words, the pilots help provide the data for a more adequate accounting of future project benefits. An example is non-wire alternative (NWA) projects. These NWA pilot projects focus on using alternative technologies to address circuit or substation overload concerns to help delay or offset traditional grid upgrades. The Company developed these NWA pilots to better understand the customer and costs benefits as part of the longer-term grid modernization plan, so that in the future these can be evaluated against more traditional alternatives. These pilots are supported by Company witness Hartwick and detail is provided in Exhibit A-12 Schedule B5.4.1 through B5.4.7 and B5.4.9.
- Capital projects are subject to development milestones, especially in the conceptual design and early development stages, including land availability and property purchases, municipal approvals and construction permits, right-of-way acquisition and easements, and lead times when procuring major equipment. While the Company takes proactive measures to mitigate these execution risks, many of these early-stage milestones are difficult for the Company to control and can introduce schedule delays or cost increases. Therefore, the Company's investment and maintenance plan is designed to include some flexibility to accommodate these unpredictable variations in timing and cost.

- Some capital replacement programs are funded annually, to avoid acceleration of asset failures and the risk that a large quantity of assets would reach end-of-life concurrently, thus exceeding available resources to replace them (e.g., underground residential distribution cable program).
- If the Company is awarded grant money from the state or federal government for specific projects, including IIJA grants, it could positively impact project selection due to grant project completion requirements. In 2023, the Company was awarded an Adaptive Networked Microgrids (ANMs) grant which the Company has funded in both 2024 and 2025. This project is further discussed by witness Hartwick.
- Projects already in active construction.
- Some Operational Technology (OT) projects are not evaluated through the GPM, as the GPM is designed for investments which upgrade the physical distribution grid. The specific benefits which OT projects deliver are discussed in more detail in witness Hartwick's testimony.

It is important to note that some programs and projects may not receive funding in a particular year due to lower benefit-cost scores relative to other projects, but this does not indicate that these programs or projects are not beneficial to customers, or that they will not be selected in other years. Rather, all the programs and projects identified by the Company and evaluated by the GPM provide system improvements and may be funded at some point over the next several years. While the strategic capital investment plan is primarily driven by the GPM, the Company may adjust the annual plans based on changing circumstances and grid needs.

Q82. Do the GPM scores and rankings have the potential to change over time?

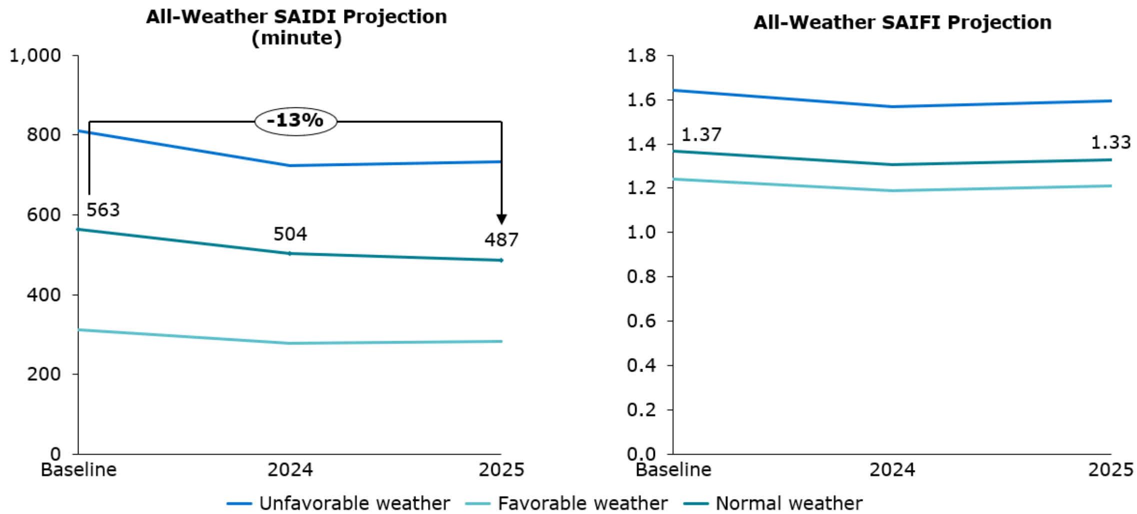
A82. Yes. As the Company continues to make investments in distribution infrastructure, the effectiveness of the capital investment is examined on a regular basis. The benefit-cost scores of the programs and projects may change over time as new data becomes available. The prioritization ranking of the programs and projects may change accordingly.

Part IX: Capital/Reliability Model

Q83. Based on DO investments requested in this case, what system reliability improvements are expected?

A83. The Company's reliability model projects that customers will experience an all-weather SAIDI of 504 minutes in 2024 and 487 minutes in 2025 versus a historical baseline of 563 minutes, assuming normal weather. Similarly, all weather SAIFI will improve to 1.33 in 2025 from the historical baseline of 1.37. The model assumes that due to timing of the execution of projects and programs, half of the benefits are realized in the year of construction and full benefits are realized the following calendar year. Graphs of expected reliability improvements are shown in **Figure 10.**

Figure 10 All-Weather Reliability Projections



Q84. How does the Company calculate its reliability projections?

A84. The reliability calculations are performed at a circuit level based on historical performance and the impact of planned investments on those circuits. The projected performance of all circuits is summed to provide a system level projection. The process to project reliability performance within the model can be summarized in five steps:

- **Baseline:** Calculate circuit-level baseline reliability performance
- **Program impact:** Estimate impact of reliability programs
- **Degradation impact:** Estimate impact of system degradation
- **Investment plan:** Enter planned or expected in-service schedule for reliability programs into model
- **Calculate Ex-MED performance:** Combine baseline performance with investment plan on a circuit level to project future performance
- **Calculate All-weather performance:** Scale Ex-MED output to all weather output and expected ranges

Each of these steps is described briefly below.

Q85. How is the starting point, or circuit baseline calculated?

A85. Each circuit has a baseline of reliability performance based on five years of historical, non-MED event volume. Events are further divided into tree and non-tree, single and multiple, and outage and non-outage events. An average customer's interrupted (CI) and customer minutes interrupted (CMI) per event is used to convert the volume of events to a SAIDI Ex-MED and SAIFI ex-MED baseline.

Q86. Which reliability investments are included in the model?

A86. The model's purpose is to forecast system reliability based on outage events on the overhead distribution system (where the vast majority of the Company's outage events occur), and therefore incorporates the impact of projects and programs which have the potential reduce the impact of overhead outage events. The model accounts for reliability improvements from six programs: Tree Trimming, 4.8kV Hardening, PTMM, Customer Excellence, 4.8kV Conversion, and Automation.

Q87. How does the company estimate the effectiveness of the reliability investments?

A87. For programs that have been established for over 3 years, the Company looks at a year worth of non-MED historical circuit outage data before reliability improvement is deployed. Non-MED event data for years post deployment is compared to the baseline to calculate the reliability improvement. For newer programs or projects, the reliability improvement is based either on the assessment from industry subject matter experts, including DTE's Engineering, or by comparing the newer program to similar established programs. Programs impact the event types they are most likely to avoid. For example, if a circuit has tree trimming planned, the model will project a reduction in tree-related multiple events.

Q88. How is the circuit performance projected?

A88. The investment plan is entered in the model on a circuit level basis. For example, the model has a list of circuits with planned PTMM in 2024 which is aligned with our investment plan. If a circuit has no planned investment indicated in the model, the model will calculate an increase in future event volume, or degradation, over time. Circuits which have Tree Trimming, 4.8kV Hardening, PTMM, or Customer Excellence work will have the program benefits applied to them by reducing the future volume of events. Half of the maximum benefit will be applied in the year of the investment, and the total benefit in the year after the investment. The benefit will reduce over time due to factors such as the regrowth of trees, and the continued aging of overhead equipment. The model assumes that significant rebuild work from 4.8kV Conversion will deliver a consistent benefit for 10 years after the investment without any degradation. The impact of the Automation investment is a reduction in the customer interrupted (CI) per event on the circuit, but there is no associated reduction in event volume.

Q89. How are Ex-MED and all-weather reliability metrics calculated?

A89. The primary output of the model is a projection of ex-MED event volume, which is translated into SAIFI ex-MED and SAIDI ex-MED using a historical event average CI and CMI per event. The ex-MED results are scaled to all-weather

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projections by calculating the ex-MED to all weather performance relationship of 64 large utilities based on historical data available on EIA.gov. As an example, for utilities who had a SAIDI ex-MED of 100 minutes in a given year, the range of All-Weather SAIDI outcomes, excluding the top and bottom 20% of outcomes, was 140 minutes to 342 minutes. If the model projects the Company's SAIDI ex-MED performance to be 100 minutes, it would also calculate a range of expected All-weather outcomes to be 140 to 342 minutes, with an average performance calculated as the median of the data set. This range, based on industry performance, accounts for weather variability.

Q90. Does the model capture all potential reliability benefits?

A90. No, as mentioned the model captures the benefits of the investment programs which deliver the majority of the improvements on the overhead distribution system. Other programs such as URD replacement, Cable replacement, Breaker replacement, Substation Risk projects will also reduce outage events and impact reliability. For specific benefits from these projects, please refer to testimony from Witnesses Elliott Andahazy, Deol, and Hartwick.

Q91. How is this model an improvement upon previous reliability projections?

A91. The structure of this model has many improvements over previous methods to project reliability. First, the model is based on ex-MED events and reliability which has less inherent variability than all-weather performance. Second, by modelling the system on a circuit level basis, this methodology more accurately accounts for benefits from different programs without double counting. Finally, as circuit performance is disaggregated into many event types (tree vs non tree, single vs multiple, outage vs non-outage), program improvements can more accurately be modelled against the events they are most likely to address.

Q92. Does the reliability model project emergent reductions and how are these reductions shown in Exhibit A-12 Schedule B5.4?

A92. Yes. The reliability model projected emergent reduction, along with the surge tree trim capital reduction shown on Exhibit A-22, Schedule L1, line 33, are shown in Exhibit A-12, Schedule B5.4, page 1, line 6.

<u>Part X: IIJA Grant Opportunities</u>

Q93. What are IIJA grants?

A93. The Infrastructure Investment and Jobs Act (IIJA)) was enacted federally in November 2021. The goal of the IIJA grants is to provide funding opportunities in multiple types of investments to catalyze public and private investment to enhance the nation's infrastructure, with a particular focus on helping America's disadvantaged communities. For electric infrastructure, the grants are mainly administered in three broad categories: improving grid resilience, building smart grids, and pursuing grid innovation.

Q94. Did the Company seek grant funding to invest in the distribution system in 2023?

A94. Yes. In 2023, the Company applied for two direct grants to improve the distribution system: Section 40101(c) – Grid Resilience and Section 40107 – Smart Grid. The company also applied for a grant from the Michigan Department of Environment, Great Lakes, and Energy (EGLE), who is administering funds awarded through

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Section 40101(d) – Preventing Outages and Enhancing the Resilience of the Electric Grid. Additionally, the Company was a partner on an application for Section 40103(b) – Grid Innovation Program. This grant was led by the State of Michigan.

Q95. Were any of the Company's IIJA grant applications selected to be funded?

A95. Yes. The DOE (Department of Energy) selected the Company's Section 40107 – Smart Grid application for investment in October 2023. This project will deploy Adaptive Network Microgrids (ANM) on the distribution system in two communities and is discussed in Witness Hartwick's testimony. The Company received positive feedback on its Section 40101(c) – Grid Resilience grant from the DOE on the application, although was not selected. The Company is currently waiting to hear the outcome for its Section 40101 (d) – Preventing Outages and Enhancing the Resilience of the Electric Grid application filed on November 17th, 2023. DTE Electric expects a response from EGLE in the first half of 2024.

Q96. Will the Company continue to seek additional IIJA grant funding to invest in the distribution system in 2024?

A96. Yes. The Company is currently pursuing the second round of funding for Section 40101 (c) – Grid Resilience, incorporating he feedback from the DOE on project scope and strategic alignment. The Company filed a concept paper on January 12, 2024 and will continue to update our IIJA grant planning as requested with reports filed in U-21227.

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Q97. What are the objectives and details of the 40101(d) Preventing Outages and Enhancing the Resilience of the Electric Grid grant?

A97. Unlike the two grants (Section 40101c and Section 40107), this grant is an indirect grant for which the Company cannot directly apply. Instead, EGLE applied for DOE funding with the support of the MPSC. EGLE was awarded the grant on June 30, 2023 and the Request for Proposal (RFP) was posted on EGLE's website on October 3, 2023. The objectives of this grant are similar to the 40101(c) grant, with a focus on improving energy resilience and investing in modernized grid infrastructure, and are restricted to large utilities applicants. Overall, EGLE intends to award approximately $8 million in funding between the two largest utilities in the state of Michigan (DTE Electric and Consumers Energy). The Company filed an application on November 17, 2023. The Company's grant proposal is to support activities that will harden and modernize electric services for residential customers in Detroit and Highland Park with the impact of reducing electrical service outages during storm for disadvantaged communities. These outages can have significant economic impact due to loss of food or medicine, and cost of temporary shelter. The proposal will investigate the most viable option to scale up a program to harden electric service lines within the Company's service territory. Amongst the proposed options for hardening services are (1) undergrounding overhead services, and (2) replacing overhead services and tree trimming away from services. Additionally, newly hardened residential services will be brought up to the Company's current standard and will be capable of supporting future electrification.

Q98. Is the Company requesting funding in this rate case for investments or expenses that may be partially covered by any of the grants discussed above?

A98. Yes. The investment beyond the grant funding needed for the Section 40107 - Smart Grid award is covered in the Adaptive Networked Microgrid section of Witness Hartwick's testimony. The Company is not seeking funding for the other two grants that are still being pursued in this rate case.

Q99. If the Company is successful at obtaining any of the grants discussed above but not yet awarded, what will the Company's financial obligation be?

A99. For the grants the Company is actively pursuing, a 1:1 funding match of federal funds will be required. For example, in the 40101(c) grant application, if DOE awards $100 million of funding, DTE would need to contribute a minimum of $100 million in matching funds. DTE Electric customers would receive system improvements through the federal grants without having to fund the full investment in the project(s) through electric rates. Because this case does not include any requested investment for DTE Electric's match, it is expected that the cost recovery for the Company's match amounts would be requested in future rate cases.

Q100. What happens if the grant requires that the Company provide matching funding for a grant project before it can be presented for approval in a future rate case?

A100. The Company will notify the Commission through the ongoing docket on IIJA grants (U-21227) and discuss needed adjustments to the capital plan and funding allocations.

<u>Part XI: Environmental Justice</u>

Q101. How does the Company define environmental justice (EJ)?

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A101. The Company defines EJ in the context of the State of Michigan's definition of environmental justice as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn."[8]

Q102. How did DTE Electric incorporate EJ in grid planning as described in the 2023 DGP?

A102. Building on the 2021 DGP, the Company developed three key EJ objectives for the 2023 DGP; (1) incorporate EJ considerations in investment decisions by including an EJ component in the Global Prioritization Model (GPM), (2) improve system performance for vulnerable communities experiencing poor reliability through our investment programs, and (3) provide support to vulnerable customers experiencing outages during storms through community outreach efforts.

Q103. Does the Company continue to leverage the State of Michigan MiEJScreen tool for environmental justice data and the identification of vulnerable communities?

A103. Yes. DO continues to use the MiEJScreen Tool for its EJ data in analyzing investment impacts on disadvantaged customers and communities. EGLE released the draft version of the MiEJScreen tool in March of 2022, following extensive stakeholder involvement including a public comment process.[9] This tool combines environmental conditions and population characteristics to highlight, by census

[8] State of Michigan, Department of Environment, Great Lakes, and Energy, https://www.michigan.gov/egle/public/learn/environmental-justice, accessed January 23, 2024.
[9] MiEJScreen: Environmental Justice Screening Tool (DRAFT) (michigan.gov) available at https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict

tract, where the most vulnerable communities in Michigan are located. EGLE does not explicitly define the threshold for which communities are vulnerable and which ones are not vulnerable. A final MiEJScreen tool has not been released.

Q104. How did DTE Electric Distribution Operations define a vulnerable community for use with the draft MiEJScreen Tool?

A104. An 80% threshold definition was adopted for vulnerable communities using the draft MiEJScreen Tool score, consistent with the U.S. EPA approach.[10] Following this approach, census tracts with a MiEJScreen composite score at or above the 80th percentile are considered vulnerable communities for the purpose of this testimony and associated analysis. The draft MiEJScreen composite score is calculated using categories and indicators for environmental and population data as shown in **Figure 11** below. On November 18, 2022 the Commission directed its Energy Affordability and Accessibility Collaborative to address definitions of terms such as environmental justice, grid equity, and energy justice (Case No. U-20836, pp 462-463).

[10] 80th percentile, EPA, https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5, accessed January 24, 2024.

Figure 11 MiEJScreen Overall Score Calculation

Categories	Environmental Exposure	Environmental Effects	Sensitive Populations	Socioeconomic Factors
Indicators	NATA Air Toxics Cancer Risk NATA Respiratory Hazard Index NATA Diesel Particulate Matter Particulate Matter ($PM_{2.5}$) Ozone Traffic Density	Proximity to Cleanup Sites Proximity to Hazardous Waste Facilities Impaired Water Bodies Proximity to Solid waste Sites and Facilities Lead Paint Indicator Proximity to RMP Sites Wastewater Discharge Indicator	Asthma Cardiovascular Disease Low Birth Weight Infants Blood Lead Level Life Expectancy	Low Income Population Black, Indigenous, People of Color Population Educational Attainment Linguistic Isolation Population Under Age 5 Population Over Age 64 Unemployment Housing Burden
Sub Scores	**Environmental Conditions** (Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators) / 1.5		**Population Characteristics** (Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators) / 2	
Score	Final Composite Score = Environmental Conditions score x Population Characteristics score **MiEJScreen Score**			

Q105. Is the Company able to group reliability statistics by geographic area (i.e., census tracts and zip codes) and align to scores from the draft MiEJScreen Tool?

A105. Yes. DTE Electric tracks reliability statistics by customer, which are then rolled up to a circuit and substation. However, circuits often cross more than one census tract or zip code. DTE Electric has matched residential meters to the census tracts defined by the U.S. Census Bureau. Commercial properties are not surveyed as part of the U.S. Census, and therefore, their addresses and associated meters are not assigned to a census tract for the purposes of this analysis. There are some residential meters, due to ongoing data cleaning work, that have yet to be placed in a census tract/zip code. Currently, most meters have been successfully mapped to zip code and census tract. There are some small census tracts with a small number of customers where reliability statistics may be abnormally high or low due to small sample size.

Q106. Using available data, is the Company able to provide a geographic representation of 2023 electric reliability data by census tracts?

A106. Yes. Using the meters that are matched to census tracts, DTE Electric developed reliability data for SAIFI and SAIDI by census tract and grouped the data into DTE Electric reliability quartiles, with first quartile customers (shown below in green) experiencing the best reliability and fourth quartile customers (shown below in red) experiencing the worst reliability. Looking specifically at outage frequency, first quartile reliability customers have a 2023 All-Weather SAIFI performance fewer than 0.81 interruptions, second quartile customers range between 0.81 and 1.42 interruptions, third quartile customers are between 1.42 and 2.31 interruptions, and fourth quartile customers have performance greater than 2.31 interruptions. Looking at outage duration, first quartile reliability customers have a 2023 All-Weather SAIDI performance less than 331 minutes, second quartile customers range between 331 and 957 minutes, third quartile customers are between 957 minutes and 2,140 minutes, and fourth quartile customers have experienced outage duration above 2,140 minutes. As discussed in Part I above, for 2023, a key impact on All-Weather SAIDI was the single large ice/snow storm in February, 2023, which significantly impacted both SAIDI and SAIFI reliability metrics. Maps for SAIFI and SAIDI by census tract are included in **Figure 12 to Figure 15**.

Figure 12 2023 All Weather SAIFI by Census Tract

for DTE Electric (Full Electric Service Area)

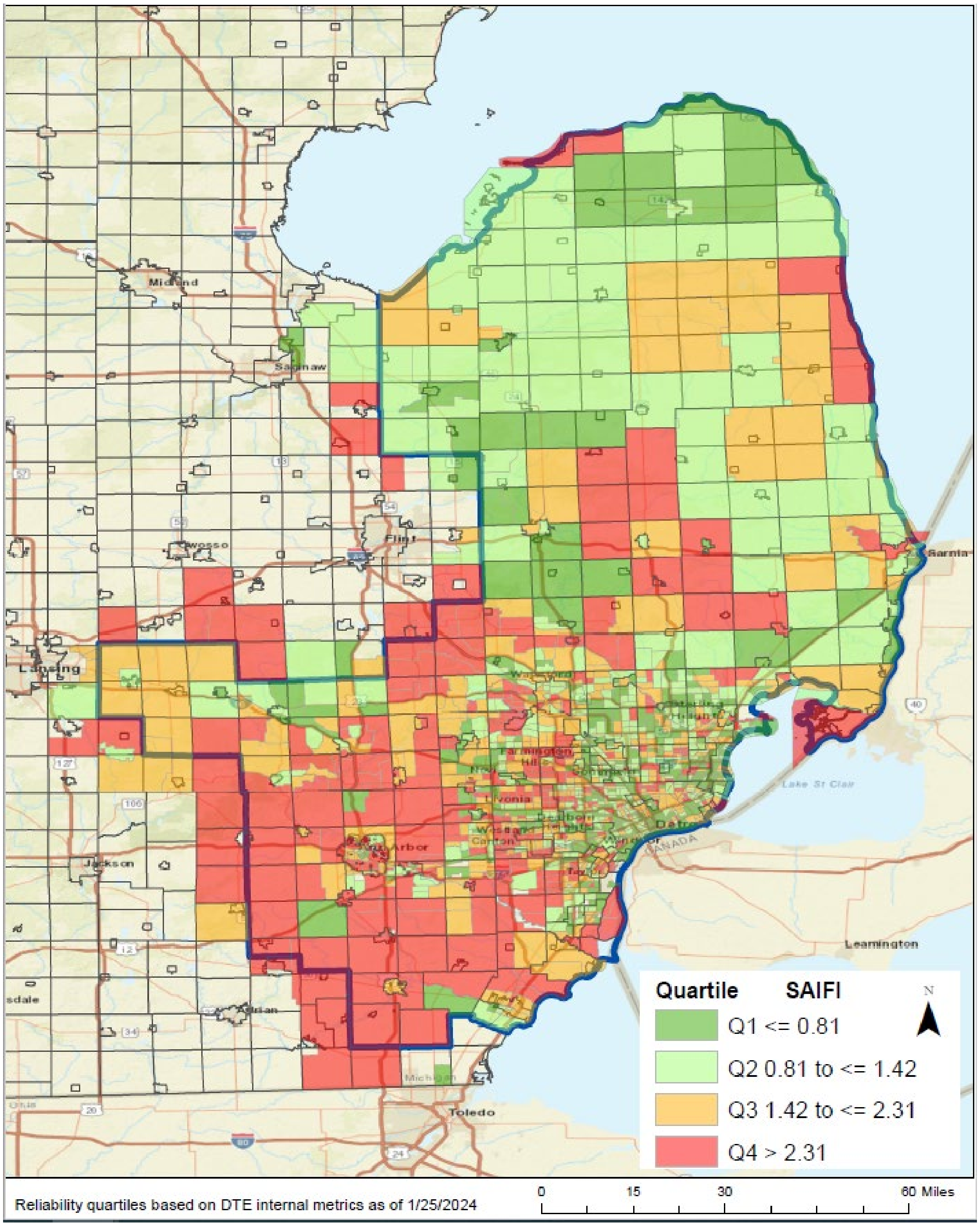

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Figure 13 2023 All Weather SAIFI by Census Tract

for DTE Electric (Metro Detroit Area)

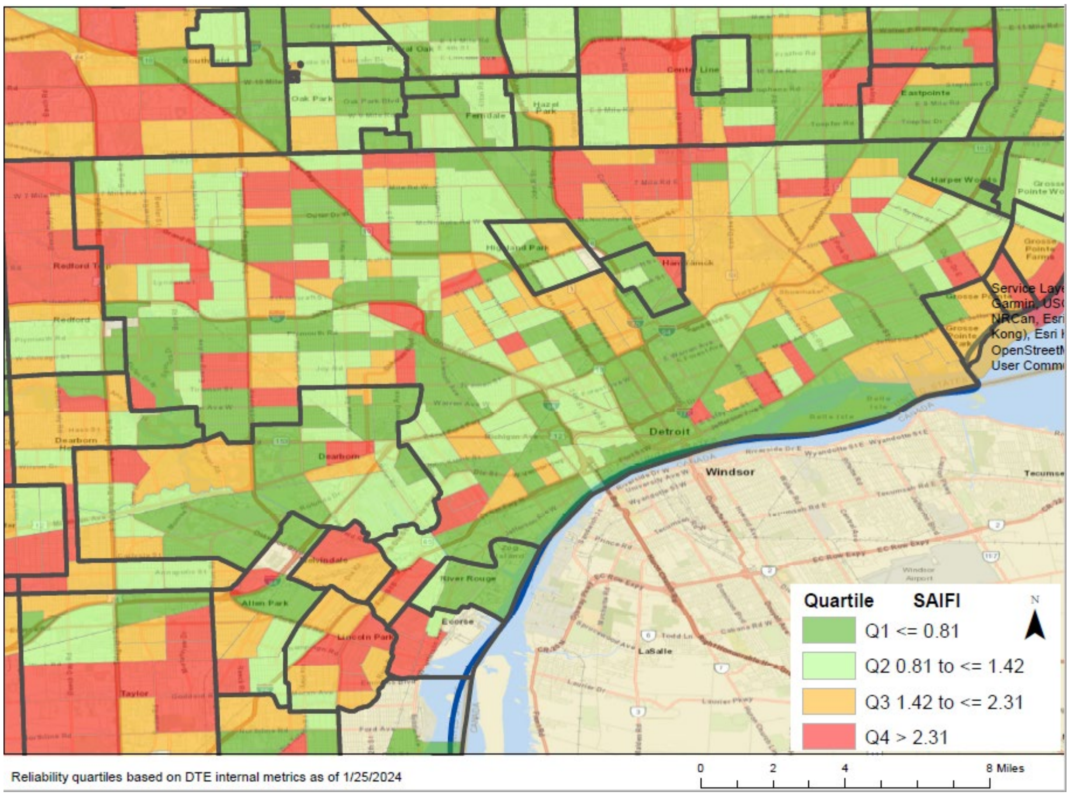

Figure 14 2023 All Weather SAIDI by Census Tract for DTE Electric (Full Electric Service Area)

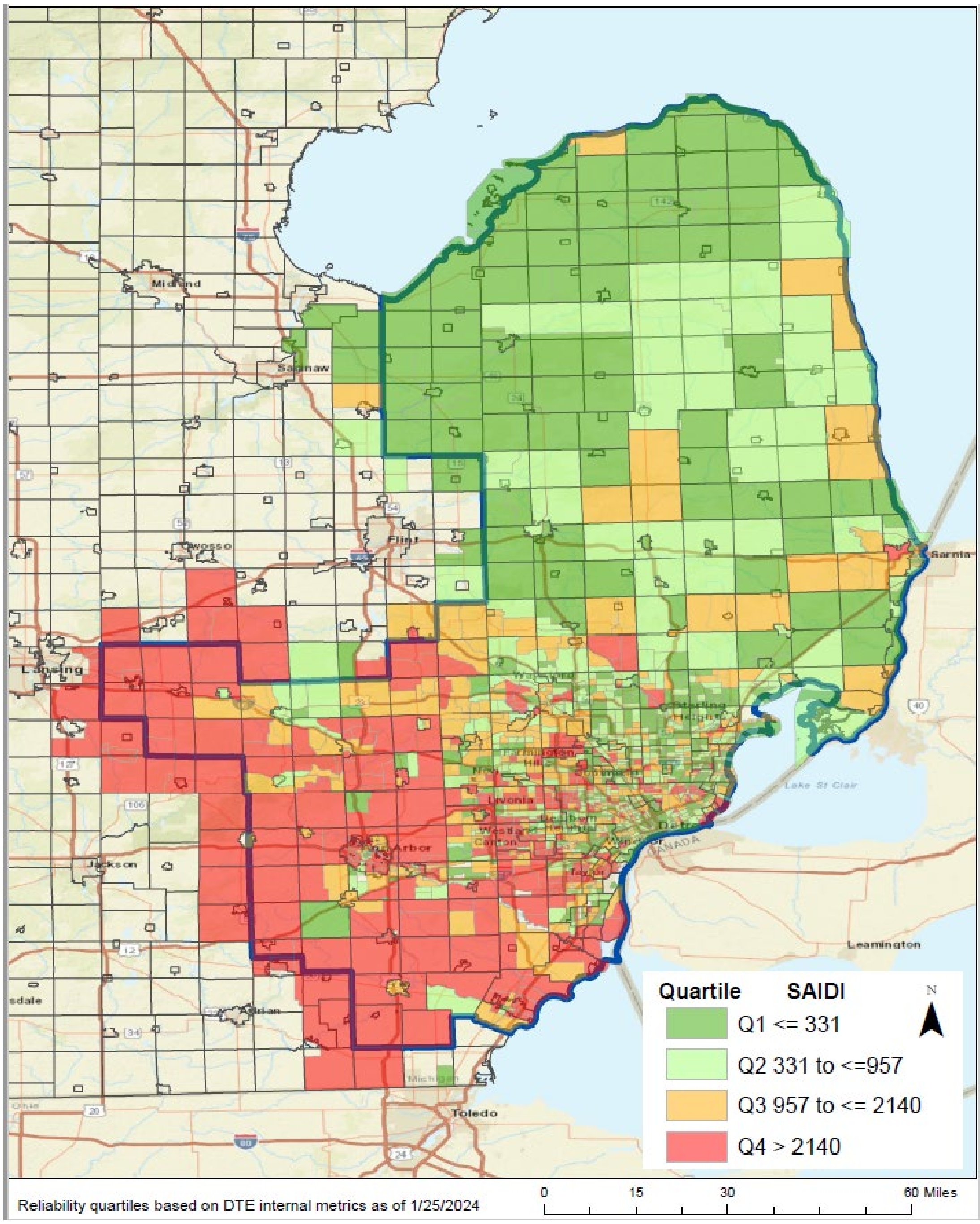

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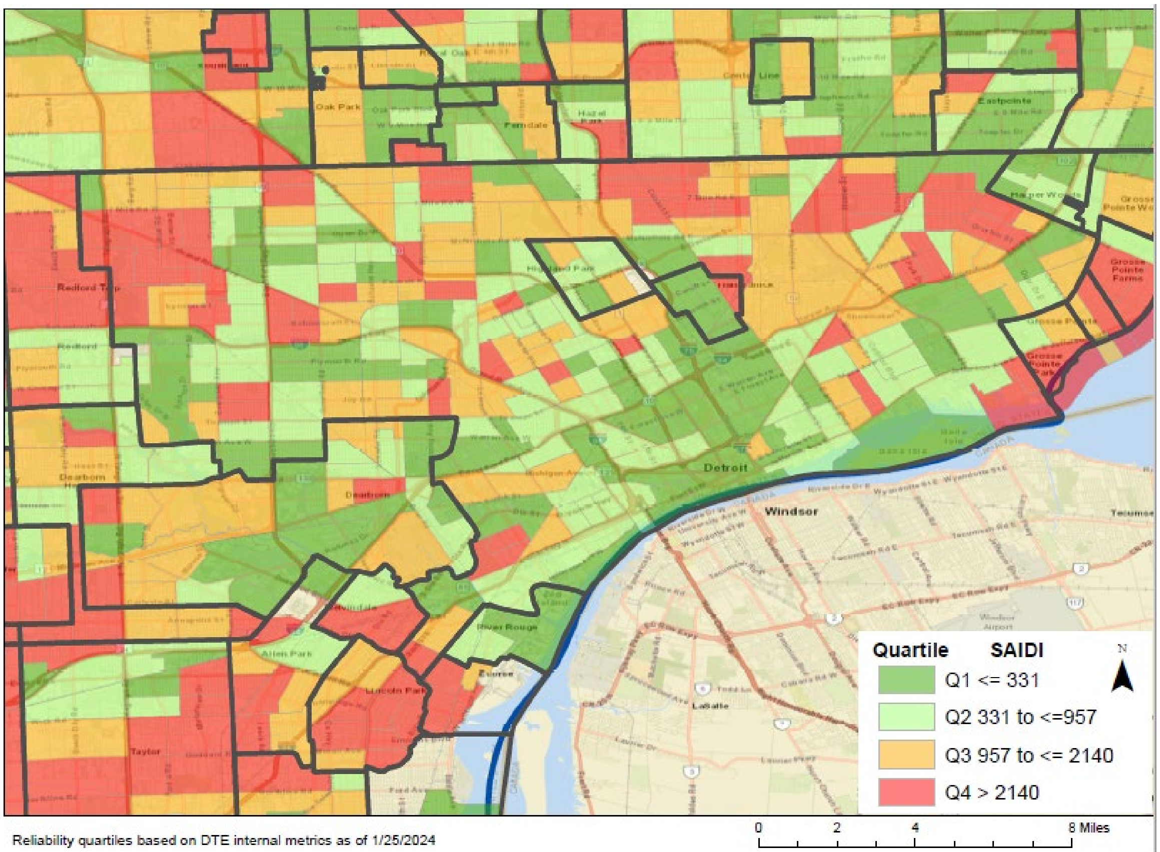
Figure 15 **2023 All Weather SAIDI by Census Tract for DTE Electric (Metro Detroit Area)**



Q107. Are all census tracts equal in geographic size and population?

A107. No. Census tracts vary in geographic size and population. According to the U.S. Census Bureau, census tracts generally have a population size between 1,200 and 8,000 people, with an optimum size of 4,000 people.[11] In addition, the geographical size of the tract does not represent how many people are in it. In some areas there are large tracts (both first and fourth quartile) that have fewer customers in them, compared to much smaller sized tracts in more dense urban areas. When the reliability data is looked at in a map, as shown above, the lightly populated, geographically large census tracts can visually skew the true reliability impact on customers.

Q108. How many vulnerable census tracks are there in DTE Electric's service territory?

A108. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80th percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and account for approximately 550,000 residential customers.[12] Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's 3,273 distribution circuits (32% of total circuits) and contain 8,289 circuit miles compared to 41,905 total distribution circuit miles (20% of total distribution miles).

Q109. What was the Commission's direction in Case No. U-21297 regarding more in-depth EJ analysis?

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[11] US Census Bureau, Glossary, available at Glossary (census.gov), https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13 accessed January 14, 2023.
[12] There are a total of 1,643 census tracts in DTE Electric's service territory.

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A109. The Commission stated in its order that future analysis of the MiEJScreen data should be segmented in 5% gradations. As stated on page 93 of the U-21297 order: "The Staff recommends, and the Commission agrees, that these gradations should be defined initially as 0% to <5%, 5% to <10%, in 5% gradations up to 95%-100% of the MiEJScreen composite score".

Q110. Has the Company performed analysis with 5% gradations of the MiEJScreen relative to reliability performance?

A110. Yes. The reliability performance in years 2020 through 2023, for SAIDI and SAIFI metrics excluding MEDs and All-Weather compared to the systemwide levels are shown in **Tables 10-13.**

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Table 10 All Weather SAIFI Reliability Performance of Census Tracts (MiEJ score of 0% to 100%) Versus System Average

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	AW	3.12	2.88	2.37	3.01
>5 to 10	AW	2.46	2.47	1.95	2.22
>10 to 15	AW	1.68	2.29	1.94	1.97
>15 to 20	AW	2.13	2.00	1.49	2.02
>20 to 25	AW	1.55	2.29	1.56	2.15
>25 to 30	AW	1.47	2.01	1.43	1.99
>30 to 35	AW	1.26	1.96	1.49	1.93
>35 to 40	AW	1.32	1.72	1.31	2.21
>40 to 45	AW	1.08	1.50	1.12	1.86
>45 to 50	AW	1.42	1.58	1.17	1.64
>50 to 55	AW	1.25	1.53	1.16	1.68
>55 to 60	AW	1.10	1.39	1.37	1.52
>60 to 65	AW	1.18	1.29	0.96	1.51
>65 to 70	AW	1.15	1.48	1.18	1.90
>70 to 75	AW	1.29	1.58	1.13	1.58
>75 to 80	AW	1.20	1.50	1.08	1.71
>80 to 85	AW	1.23	1.56	1.18	1.47
>85 to 90	AW	1.11	1.14	1.12	1.54
>90 to 95	AW	1.04	1.33	1.03	1.52
>95 to 100	AW	0.83	1.19	1.15	1.49
No EJ Score	AW	0.83	0.92	1.01	1.27
Sytem Average	AW	1.29	1.58	1.25	1.72

Over performing system average

Under performing system average

System average

Table 11 Excluding MEDs SAIFI Reliability Performance of Census Tracts (MiEJ score of 0% to 100%) Versus System Average

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	Ex-MED	2.36	1.84	1.94	1.56
>5 to 10	Ex-MED	1.71	1.35	1.54	1.27
>10 to 15	Ex-MED	1.17	1.47	1.55	1.01
>15 to 20	Ex-MED	1.57	1.15	1.25	1.17
>20 to 25	Ex-MED	1.15	1.42	1.33	1.15
>25 to 30	Ex-MED	1.12	1.16	1.17	1.13
>30 to 35	Ex-MED	0.97	1.06	1.16	0.88
>35 to 40	Ex-MED	1.02	0.99	1.00	1.10
>40 to 45	Ex-MED	0.91	0.85	0.88	0.81
>45 to 50	Ex-MED	1.14	0.94	0.98	0.75
>50 to 55	Ex-MED	1.07	0.85	0.91	0.82
>55 to 60	Ex-MED	0.88	0.84	1.10	0.77
>60 to 65	Ex-MED	0.95	0.76	0.75	0.75
>65 to 70	Ex-MED	0.98	0.84	0.98	0.93
>70 to 75	Ex-MED	1.07	0.95	0.90	0.75
>75 to 80	Ex-MED	1.01	0.93	0.85	0.87
>80 to 85	Ex-MED	0.93	0.92	0.92	0.70
>85 to 90	Ex-MED	0.85	0.68	0.78	0.71
>90 to 95	Ex-MED	0.80	0.78	0.76	0.71
>95 to 100	Ex-MED	0.65	0.64	0.77	0.78
No EJ Score	Ex-MED	0.71	0.58	0.86	0.60
Sytem Average	Ex-MED	1.01	0.92	0.98	0.86

Over performing system average

Under performing system average

System average

Table 12 All Weather SAIDI Reliability Performance of Census Tracts (MiEJ score of 0% to 100%) Versus System Average

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	AW	978	2656	1262	3278
>5 to 10	AW	863	1657	909	1604
>10 to 15	AW	384	930	916	1618
>15 to 20	AW	605	1096	576	1184
>20 to 25	AW	510	1291	527	1937
>25 to 30	AW	414	1174	611	1521
>30 to 35	AW	306	1211	692	1748
>35 to 40	AW	351	1027	666	1889
>40 to 45	AW	222	940	433	1834
>45 to 50	AW	330	999	426	1584
>50 to 55	AW	292	946	458	1482
>55 to 60	AW	300	775	531	1268
>60 to 65	AW	297	764	473	1363
>65 to 70	AW	228	816	416	1745
>70 to 75	AW	336	844	472	1515
>75 to 80	AW	325	820	389	1509
>80 to 85	AW	480	978	556	1419
>85 to 90	AW	351	705	735	1699
>90 to 95	AW	329	840	749	1675
>95 to 100	AW	266	804	923	1133
No EJ Score	AW	203	355	300	778
Sytem Average	AW	352	927	584	1542

	Over performing system average
	Under performing system average
	System average

Line No.

Table 13 Excluding MEDs SAIDI Reliability Performance of Census Tracts (MiEJ score of 0% to 100%) Versus System Average

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	Ex-MED	342	398	487	373
>5 to 10	Ex-MED	291	213	296	320
>10 to 15	Ex-MED	153	209	274	236
>15 to 20	Ex-MED	218	150	238	212
>20 to 25	Ex-MED	168	248	182	239
>25 to 30	Ex-MED	176	177	188	217
>30 to 35	Ex-MED	123	136	152	158
>35 to 40	Ex-MED	147	138	146	173
>40 to 45	Ex-MED	108	111	103	152
>45 to 50	Ex-MED	154	149	131	135
>50 to 55	Ex-MED	144	124	128	136
>55 to 60	Ex-MED	102	112	150	155
>60 to 65	Ex-MED	132	114	138	139
>65 to 70	Ex-MED	101	131	120	138
>70 to 75	Ex-MED	154	122	115	119
>75 to 80	Ex-MED	124	128	106	145
>80 to 85	Ex-MED	158	147	156	149
>85 to 90	Ex-MED	123	111	123	130
>90 to 95	Ex-MED	136	112	115	129
>95 to 100	Ex-MED	118	94	129	142
No EJ Score	Ex-MED	97	68	98	80
Sytem Average	Ex-MED	142	136	146	157

Over performing system average

Under performing system average

System average

Q111. What is the distribution of residential customers in each EJ Gradation?

A111. The distribution of residential customer in each gradation is highlighted in **Table 14** below. Approximately 27% of our residential customers fall into the 80% to 100% gradations.

Table 14 Residential Customers by EJ Gradations

Census Tract EJ % Group	Number of Residental Customers	% of Residental Customers
0-5%	7,569	<1%
5-10%	39,705	2%
10-15%	62,143	3%
15-20%	43,497	2%
20-25%	59,888	3%
25-30%	88,033	4%
30-35%	100,487	5%
35-40%	99,318	5%
40-45%	102,680	5%
45-50%	114,416	6%
50-55%	120,730	6%
55-60%	135,206	7%
60-65%	124,240	6%
65-70%	126,463	6%
70-75%	100,278	5%
75-80%	146,161	7%
80-85%	127,270	6%
85-90%	162,145	8%
90-95%	143,144	7%
95-100%	114,874	6%
Unmapped/Unscored*	38,383	2%
Total Residential Customers	2,056,630	100%

Q112. How does the reliability performance of census tracts that have been identified as vulnerable communities compare with the rest of the DTE Electric system?

A112. As noted in **Table 10** and **Table 12**, vulnerable customers in the 80th percentile and above see better reliability than the system average in SAIFI and SAIDI in both All-Weather and Non-MED. All-Weather and Non-MEDs SAIFI is lower than the system average in every year and every vulnerable community gradient. For Non-MED SAIDI, the vast majority of years and vulnerable community gradients are better than the system average. All-Weather shows more year-gradient combinations above the system average but even for this metric, the majority of instances are better than the system average.

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Q113. Has the company evaluated how its investment programs are reaching vulnerable communities to improve electric distribution infrastructure and reliability performance?

A113. Yes. The Company has evaluated some of its largest distribution investment projects and programs, 4.8kV Hardening, 4.8kV Conversion, and tree trim, with respect to if the investment was made in a vulnerable area.

Q114. What are the results of the investment analysis related to vulnerable communities?

A114. The results are summarized in **Table 15** below and indicate that the Company's investments are supporting vulnerable customers and communities in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2023: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment programs, **Table 15** shows total investment dollars by program, total program investment in vulnerable communities, and percentage of program investment in vulnerable communities. For example, of the nearly half billion dollars of investment in the 4.8kV Hardening program since 2018, 85% of work performed under the hardening program occurred in vulnerable communities. As discussed by Witness Elliott Andahazy, the hardening program has resulted in documented reliability and safety improvements, including reduction in the frequency and duration of outages and fewer downed wires, through the program's clearing of right of way, equipment upgrades, and removal of arc wire.

Table 15 2018 to 2023 Investment in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)

Investment Program (2018-2023)	Total Investment by Program ($M)	Total Investment by Program in Vulnerable Census Tracts ($M)	% Of Investment in Vulnerable Census Tracts
Conversion	$396	$255	**64%**
4.8kV Hardening	$494	$418	**85%**
Tree Trim	$962	$242	**25%**

Q115. How will these distribution investment programs address vulnerable communities in 2024-2025 based on the Company's planned execution of investments in this case?

A115. For the purpose of this analysis, the Company focused on three of the largest strategic investment programs, Witness Deol, Witness Elliott Andahazy, and Witness Steudle address the Company's planned investments for 2024 and 2025 for conversions, hardening, and tree trimming, respectively. **Table 16** below summarizes total investment dollars by program, total program investment in vulnerable communities, and percentage of program investment in vulnerable communities in 2024-2025.

Line No.

Table 16 2024-2025 Investment in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)

Investment Program (2024-2025)	Total Investment by Program ($M)	Total Investment by Program in Vulnerable Census Tracts ($M)	% Of Investment in Vulnerable Census Tracts
Conversion	$475	$288	**61%**
4.8kV Hardening	$205	$185	**90%**
Tree Trim	$285	$81	**28%**

Q116. Is the Company also analyzing investments in 5% EJ gradations as directed in the December 2023 order in Case No. U-21297?

A116. Yes. The Company analyzed investments pertaining to Hardening, Tree Trim, and Conversion including City of Detroit Infrastructure (CODI) programs, to provide information in EJ community gradations based on the MiEJScreen score as defined in the December 2023 order. The gradations are defined as 0% to 5%, >5% to 10%, in 5% gradations up to >95% - 100% of the MiEJScreen composite score, the same as the reliability analysis above. **Tables 17** to **Table 22** below demonstrates the Company's investment distribution for EJ gradations by year.

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Table 17 Hardening Investments by EJ Gradations

EJ Gradations	2018 Investment ($000)	2019 Investment ($000)	2020 Investment ($000)	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment Forecast ($000)	2025 Investment Forecast ($000)
0-5%	$ -	$ -	$ -	$ -	$ -	$ 1,710	$ -	$ -
5-10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10-15%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15-20%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20-25%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25-30%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30-35%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35-40%	$ -	$ -	$ -	$ -	$ 1,955	$ -	$ -	$ -
40-45%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45-50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50-55%	$ -	$ -	$ -	$ 6,284	$ -	$ -	$ -	$ -
55-60%	$ -	$ -	$ -	$ -	$ -	$ -	$ 211	$ -
60-65%	$ -	$ -	$ -	$ 1,669	$ 9,026	$ -	$ -	$ -
65-70%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70-75%	$ 1,077	$ 2,300	$ 1,821	$ 3,032	$ 2,747	$ -	$ -	$ 7,401
75-80%	$ 2,302	$ -	$ 868	$ 16,682	$ 1,691	$ 4,148	$ 2,177	$ 1,595
80-85%	$ 5,455	$ 12,499	$ 2,343	$ 646	$ 8,354	$ 12,660	$ -	$ 3,777
85-90%	$ 14,205	$ 18,366	$ 24,086	$ 8,858	$ 22,658	$ 32,545	$ 7,681	$ 21,978
90-95%	$ 16,413	$ 13,456	$ 15,495	$ 13,563	$ 39,625	$ 24,866	$ 20,547	$ 44,776
95-100%	$ 776	$ 1,644	$ 9,505	$ 12,315	$ 65,540	$ 40,755	$ 45,717	$ 40,409
Unmapped/Unscored*	$ 95	$ 12	$ 1,048	$ 2,313	$ 5,885	$ 10,326	$ 3,667	$ 5,063
Total Investment ($)	**$ 40,325**	**$ 48,278**	**$ 55,165**	**$ 65,362**	**$ 157,482**	**$ 127,010**	**$ 80,000**	**$ 125,000**

Table 18 Percent of Hardening Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	1%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	0%	0%
10-15%	0%	0%	0%	0%	0%	0%	0%	0%
15-20%	0%	0%	0%	0%	0%	0%	0%	0%
20-25%	0%	0%	0%	0%	0%	0%	0%	0%
25-30%	0%	0%	0%	0%	0%	0%	0%	0%
30-35%	0%	0%	0%	0%	0%	0%	0%	0%
35-40%	0%	0%	0%	0%	1%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	0%
45-50%	0%	0%	0%	0%	0%	0%	0%	0%
50-55%	0%	0%	0%	10%	0%	0%	0%	0%
55-60%	0%	0%	0%	0%	0%	0%	0%	0%
60-65%	0%	0%	0%	3%	6%	0%	0%	0%
65-70%	0%	0%	0%	0%	0%	0%	0%	0%
70-75%	3%	5%	3%	5%	2%	0%	0%	6%
75-80%	6%	0%	2%	26%	1%	3%	3%	1%
80-85%	14%	26%	4%	1%	5%	10%	0%	3%
85-90%	35%	38%	44%	14%	14%	26%	10%	18%
90-95%	41%	28%	28%	21%	25%	20%	26%	36%
95-100%	2%	3%	17%	19%	42%	32%	57%	32%
Unmapped/Unscored	0%	0%	2%	4%	4%	8%	5%	4%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

Table 19 Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment ($000)	2019 Investment ($000)	2020 Investment ($000)	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment Forecast ($000)	2025 Investment Forecast ($000)
0-5%	$ 553	$ 252	$ 948	$ 1,634	$ 3,055	$ 1,487	$ 501	$ 303
5-10%	$ 4,596	$ 4,355	$ 11,250	$ 9,290	$ 4,653	$ 9,113	$ 3,301	$ 494
10-15%	$ 7,087	$ 1,076	$ 9,756	$ 11,195	$ 12,626	$ 13,319	$ 5,131	$ 1,161
15-20%	$ 2,808	$ 2,407	$ 7,037	$ 7,118	$ 6,069	$ 8,227	$ 5,623	$ 5,258
20-25%	$ 2,809	$ 5,681	$ 8,683	$ 7,320	$ 11,946	$ 5,077	$ 11,032	$ 12,265
25-30%	$ 4,056	$ 3,714	$ 8,551	$ 15,421	$ 12,696	$ 8,208	$ 7,503	$ 5,232
30-35%	$ 3,008	$ 2,815	$ 14,158	$ 10,839	$ 16,395	$ 9,867	$ 5,498	$ 4,543
35-40%	$ 3,047	$ 5,011	$ 9,332	$ 7,666	$ 15,467	$ 8,204	$ 5,311	$ 8,483
40-45%	$ 3,415	$ 2,496	$ 4,657	$ 8,498	$ 13,595	$ 7,857	$ 3,986	$ 3,649
45-50%	$ 4,059	$ 6,039	$ 4,847	$ 7,315	$ 11,990	$ 11,789	$ 7,463	$ 5,331
50-55%	$ 2,204	$ 4,604	$ 4,730	$ 10,125	$ 13,127	$ 5,841	$ 6,768	$ 4,540
55-60%	$ 1,611	$ 4,281	$ 5,338	$ 6,987	$ 10,363	$ 6,555	$ 9,179	$ 5,565
60-65%	$ 1,746	$ 3,820	$ 5,864	$ 7,329	$ 9,856	$ 5,702	$ 3,664	$ 4,726
65-70%	$ 1,659	$ 2,560	$ 5,860	$ 4,182	$ 11,035	$ 4,402	$ 4,862	$ 7,786
70-75%	$ 1,028	$ 3,209	$ 4,676	$ 2,664	$ 4,782	$ 3,696	$ 5,259	$ 5,338
75-80%	$ 2,187	$ 3,831	$ 5,980	$ 5,654	$ 10,001	$ 5,855	$ 8,571	$ 9,488
80-85%	$ 4,758	$ 4,967	$ 3,119	$ 8,166	$ 15,094	$ 5,759	$ 8,316	$ 10,553
85-90%	$ 7,880	$ 23,046	$ 7,664	$ 6,750	$ 13,184	$ 8,647	$ 20,166	$ 5,072
90-95%	$ 7,856	$ 13,901	$ 14,559	$ 4,648	$ 16,324	$ 10,152	$ 16,101	$ 5,868
95-100%	$ 5,444	$ 14,573	$ 7,846	$ 8,734	$ 13,113	$ 15,055	$ 13,239	$ 981
Unmapped/Unscored*	$ 9,939	$ 14,193	$ 24,073	$ 10,699	$ 19,887	$ 22,648	$ 11,458	$ 15,819
Total Investment (%)	$ 81,752	$ 126,831	$ 168,926	$ 162,235	$ 245,260	$ 177,459	$ 162,930	$ 122,456

Table 20 Percent of Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	1%	0%	1%	1%	1%	1%	0%	0%
5-10%	6%	3%	7%	6%	2%	5%	2%	0%
10-15%	9%	1%	6%	7%	5%	8%	3%	1%
15-20%	3%	2%	4%	4%	2%	5%	3%	4%
20-25%	3%	4%	5%	5%	5%	3%	7%	10%
25-30%	5%	3%	5%	10%	5%	5%	5%	4%
30-35%	4%	2%	8%	7%	7%	6%	3%	4%
35-40%	4%	4%	6%	5%	6%	5%	3%	7%
40-45%	4%	2%	3%	5%	6%	4%	2%	3%
45-50%	5%	5%	3%	5%	5%	7%	5%	4%
50-55%	3%	4%	3%	6%	5%	3%	4%	4%
55-60%	2%	3%	3%	4%	4%	4%	6%	5%
60-65%	2%	3%	3%	5%	4%	3%	2%	4%
65-70%	2%	2%	3%	3%	4%	2%	3%	6%
70-75%	1%	3%	3%	2%	2%	2%	3%	4%
75-80%	3%	3%	4%	3%	4%	3%	5%	8%
80-85%	6%	4%	2%	5%	6%	3%	5%	9%
85-90%	10%	18%	5%	4%	5%	5%	12%	4%
90-95%	10%	11%	9%	3%	7%	6%	10%	5%
95-100%	7%	11%	5%	5%	5%	8%	8%	1%
Unmapped/Unscored*	12%	11%	14%	7%	8%	13%	7%	13%
Total Investment (%)	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 21 Conversion Investments by EJ Gradations

EJ Gradations	2018 Investment ($000)	2019 Investment ($000)	2020 Investment ($000)	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment Forecast ($000)	2025 Investment Forecast ($000)
0-5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5-10%	$ -	$ -	$ -	$ 127	$ 51	$ 399	$ 2,079	$ 2,735
10-15%	$ 128	$ 583	$ 660	$ 464	$ 1,118	$ 439	$ 1,601	$ 2,788
15-20%	$ 203	$ 618	$ 665	$ 2,359	$ 5,468	$ 1,748	$ 5,341	$ 1,132
20-25%	$ 511	$ 1,142	$ 692	$ 2,423	$ 7,370	$ 3,787	$ 5,099	$ 5,971
25-30%	$ 201	$ 483	$ 324	$ 523	$ 480	$ 2,094	$ 6,093	$ 4,996
30-35%	$ 225	$ 811	$ 427	$ 3,753	$ 9,445	$ 3,464	$ 7,425	$ 13,410
35-40%	$ 339	$ 159	$ 112	$ 143	$ 329	$ 319	$ 484	$ 986
40-45%	$ 11	$ 66	$ -	$ 16	$ 65	$ 235	$ 433	$ 1,824
45-50%	$ 60	$ 189	$ 14	$ 505	$ 4,188	$ 1,656	$ 1,617	$ 4,544
50-55%	$ 1,764	$ 784	$ 154	$ 380	$ 1,141	$ 887	$ 2,099	$ 5,312
55-60%	$ 82	$ 185	$ 50	$ 793	$ 2,362	$ 6,227	$ 9,902	$ (27)
60-65%	$ 1,072	$ 413	$ 176	$ 340	$ 106	$ 497	$ 1,884	$ 6,280
65-70%	$ 877	$ 275	$ 58	$ 595	$ 1,101	$ 8,909	$ 16,676	$ 144
70-75%	$ 272	$ 75	$ 114	$ 1,001	$ 295	$ 833	$ 2,378	$ 2,818
75-80%	$ 2,313	$ 2,497	$ 3,125	$ 3,149	$ 4,188	$ 11,090	$ 21,576	$ 11,318
80-85%	$ 381	$ 187	$ 183	$ 816	$ 3,335	$ 11,149	$ 9,145	$ 15,499
85-90%	$ 1,440	$ 495	$ 297	$ 2,147	$ 4,319	$ 11,646	$ 9,212	$ 17,790
90-95%	$ 2,475	$ 1,102	$ 1,157	$ 4,732	$ 8,542	$ 18,081	$ 37,126	$ 35,191
95-100%	$ 11,423	$ 9,836	$ 15,814	$ 32,162	$ 44,649	$ 67,524	$ 73,157	$ 83,132
Unmapped/Unscored*	$ 1,653	$ 690	$ 437	$ 2,665	$ 5,930	$ 11,126	$ 15,237	$ 30,475
Total Investment ($)	$ 25,429	$ 20,591	$ 24,460	$ 59,092	$ 104,483	$ 162,109	$ 228,563	$ 246,318

Table 22 Percent of Conversion Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	0%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	1%	1%
10-15%	1%	3%	3%	1%	1%	0%	1%	1%
15-20%	1%	3%	3%	4%	5%	1%	2%	0%
20-25%	2%	6%	3%	4%	7%	2%	2%	2%
25-30%	1%	2%	1%	1%	0%	1%	3%	2%
30-35%	1%	4%	2%	6%	9%	2%	3%	5%
35-40%	1%	1%	0%	0%	0%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	1%
45-50%	0%	1%	0%	1%	4%	1%	1%	2%
50-55%	7%	4%	1%	1%	1%	1%	1%	2%
55-60%	0%	1%	0%	1%	2%	4%	4%	0%
60-65%	4%	2%	1%	1%	0%	0%	1%	3%
65-70%	3%	1%	0%	1%	1%	5%	7%	0%
70-75%	1%	0%	0%	2%	0%	1%	1%	1%
75-80%	9%	12%	13%	5%	4%	7%	9%	5%
80-85%	1%	1%	1%	1%	3%	7%	4%	6%
85-90%	6%	2%	1%	4%	4%	7%	4%	7%
90-95%	10%	5%	5%	8%	8%	11%	16%	14%
95-100%	45%	48%	65%	54%	43%	42%	32%	34%
Unmapped/Unscored	6%	3%	2%	5%	6%	7%	7%	12%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

Q117. Is the investment in vulnerable communities reflective of DTE Electric's ongoing efforts to improve reliability in vulnerable communities?

A117. Yes. As highlighted in **Table 15**, 85%, 64%, and 25 % of the investment in the 4.8kV Hardening, 4.8kV Conversion, and Tree Trim programs for the time period 2018 to 2023 was made in vulnerable communities. Significant investment is expected to continue in these vulnerable communities in future years 2024-2025 as illustrated in **Table 16** including 90%, 61%, and 28% of the total investment in the Hardening, Conversion, and Tree Trim. Both the Company's historical and future projected investment, is consistent with DTE Electric's commitment to improving reliability in vulnerable communities.

Q118. Has the Company incorporated Environmental Justice considerations into the GPM for future Distribution Operations investments, including investments in this case?

A118. Yes. As described in the DGP section of testimony above, the Company has included EJ scoring from the MiEJScreen tool in the GPM calculation. Projects in more vulnerable areas will receive a higher score and have a better chance of being selected for investment.

Q119. How is the Company addressing the circuits with the worst reliability that have also been identified as serving vulnerable customers?

A119. The Company has either already invested in recent improvements or has plans to improve performance of the 4th quartile worst performing circuits that are in vulnerable communities through our investment programs, Tree Trim, PTMM, Conversion, Customer Excellence, and 4.8kV Hardening. The Company has

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identified 191 distribution circuits in vulnerable communities which fall in the fourth quartile for reliability performance based on a five-year historic average. Approximately 55% of the fourth quartile circuits have recently had reliability work performed, while 45% of the circuits are planned to be addressed in 2024-2026 investment programs.

Q120. What are the Company's future plans to address EJ in the context of distribution planning and operations?

A120. DTE Electric plans to continue to analyze reliability and investment data using the draft MiEJScreen tool, including the consideration of any updates based on the state's release of the tool's final version. The company intends continue to include EJ considerations in investment decisions for all areas, as well as continue to address poor performing circuits in vulnerable communities. Finally, DTE Electric will continue to look for potential IIJA grant opportunities that invest in infrastructure-related programs to benefit vulnerable communities in alignment with the Biden Administration's Justice40 initiative.[13]

<u>Part XII: Municipal Project Coordination</u>

Q121. What did the MPSC Case No. U-21297 order the Company to do with regard to municipal project coordination?

A121. The Commission stated on page 375 that:

[13] The White House, Justice40: A Whole-of-Government Initiative, available at: Justice40 Initiative | Environmental Justice | The White House, https://www.whitehouse.gov/environmentaljustice/justice40/?adlt=strict accessed January 14, 2023.

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"In its next general rate case, DTE Electric Company shall demonstrate its efforts to improve communication and coordination with local governments regarding construction activities, as described in this order" (page 375).

Q122. How does the Company currently coordinate projects with municipalities?

A122. When DTE is ready to move forward with a capital project the Company coordinates with the appropriate municipal personnel to set up a briefing meeting to discuss the details of the project, benefits, and collaboration opportunities of the work. We request that the municipality provide any potential conflicts to the project before permits are sought. This provides both the municipality and DTE some assurance that the planned project does not conflict with a municipal project, whether it's in the conceptual or planned stage.

Once the project is in progress, periodic updates are provided to the municipality and meetings may be held work through any questions that arise.

Q123. Does the Company have ongoing efforts to improve communication and coordination with municipalities?

A123. Yes. The company is working to improve the frequency of updates to municipalities and garnering feedback to determine their preferred methods to receiving these updates. In addition, we are working with county road commission to support their projects, and to coordinate where possible to avoid conflicts.

Q124. Does this complete your direct testimony?

A124. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT J. LEE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT J. LEE

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Robert J. Lee (he/him/his) and my business address is One Energy Plaza, Detroit, Michigan 48226-1279. I am employed by DTE Energy Corporate Services, LLC within DTE's Environmental Management and Safety team and I am currently the Manager of Environmental Strategy for the Company.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Geology in 1992 and a Master of Science Degree in Environmental Geochemistry in 1994 from the University of Wales.

Q4. What is your work experience?

A4. Since completing my formal education, I have practiced continuously in the environmental field with a focus on State and Federal programs mostly in Michigan. My past and current responsibilities include management of several environmental program areas, including Effluent Limitations Guidelines (ELG) and water permit management, Coal Combustion Residual (CCR) program management, remediation program management, State and Federal construction permit programs, and coal plant retirement. Additionally, I have State and Federal level experience supporting and developing legislative and rule-making initiatives.

From 1994 to 2004, I worked in environmental consulting and environmental engineering. I managed a wide variety of projects for various industries focusing on remediation project management, solid waste compliance, coal ash management, National Pollutant Discharge Elimination System (NPDES) permit management and obtaining and managing State and Federal permits. I also performed complex multi-site due diligence and liability management. I worked for a variety of industries including utility, cement production, and landfill industry sectors.

Q5. What are your current duties and responsibilities?

A5. I have worked for DTE Energy for 19 years. I am currently the Manager of Environmental Strategy, and my focus is on complex and strategic environmental initiatives that are critical to DTE. In this role I focus on environmental strategy, policy, and regulatory development and am responsible for key environmental programs at the State and Federal level that are critical to the Company's compliance, strategic direction, and generation strategy. I am responsible for the Company's strategy and approach for compliance with the CCR and ELG programs, coal plant retirement, asset reuse, waste program, and renewable energy development.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

U-16999	2012 DTE Gas General Rate Case
U-17999	2015 DTE Gas General Rate Case

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1	U-20642	2019 DTE Gas General Rate Case
2	U-20940	2021 DTE Gas General Rate Case
3	U-20836	2022 DTE Electric General Rate Case
4	U-21297	2023 DTE Electric General Rate Case

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. I will describe the status of two significant Environmental Protection Agency (EPA) regulations, the Steam Electric Effluent Limitation Guidelines (ELG) Rule and the Coal Combustion Residuals (CCR) Rule, which impact the Company's coal-fired power plants. I will address the following additional topics in my testimony:

1) I will explain the ELG Rule, recent revisions, and compliance strategies in support of Witness Guillaumin's discussion of ELG-related capital expenditures.
2) I will describe how the EPA's CCR Rule affects the Company's coal-fired units in support of Witness Guillaumin's discussion of CCR-related capital expenditures.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. No.

Q9. Is the Company requesting recovery of capital expenditures associated with compliance with EPA regulations?

A9. Yes. As shown in Company Witness Guillaumin's Exhibit A-12, Schedule B5.1, the Company is in the process of developing and implementing several ELG and CCR compliance projects necessitating capital expenditures, including:

- Monroe Dry Fly Ash Conversion (ELG)
- Monroe Bottom Ash Conversion (ELG)
- Monroe FGD Wastewater (ELG)

- Sibley Quarry Landfill Modification (CCR)
- Sibley Quarry Conveyor Installation (CCR)
- Sibley Quarry Infrastructure Modification (CCR)
- Sibley Quarry Landfill Dewatering and Discharging Line (CCR)
- Monroe Bottom Ash Basin Closure (CCR)
- St. Clair Bottom Ash Basin Closure (CCR)
- Belle River Bottom Ash Basin Modification (CCR)
- Monroe Fly Ash Basin Closure (CCR)

Effluent Limit Guidelines

Q10. What are the Effluent Limit Guidelines (ELGs)?

A10. Effluent Limit Guidelines are national wastewater discharge standards that are developed by the EPA on an industry-by-industry basis. These are technology-based regulations and are intended to represent the greatest pollutant reductions that are economically achievable for an industry. EPA promulgated the Steam Electric Power Generating ELGs in 1974, and amended the regulations in 1977, 1978, 1980, 1982, 2015 and 2020. The regulations cover wastewater discharges from steam electric power plants operated by utilities. The Steam Electric ELGs are incorporated into NPDES permits issued by the Michigan Department of Environment, Great Lakes & Energy (EGLE).

Q11. Can you describe the recent revisions to EPA's Steam Electric Power Generating (SEPG) ELGs?

A11. Yes. The EPA's SEPG ELGs regulate how electric utilities must manage certain wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration

Rule which revised some requirements from the 2015 version of the ELG rule. The Reconsideration Rule revised requirements for two specific waste streams produced by steam electric power plants: flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW). The Reconsideration Rule provides additional compliance opportunities by finalizing subcategories, such as for the cessation of coal burning activities. Therefore, steam electric plants can comply with ELG requirements for FGD and BATW by either meeting requirements to discharge or meeting requirements of a subcategory.

Q12. When must DTE Electric comply with revised ELGs?

A12. The Reconsideration Rule provides opportunities for DTE Electric to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in a more cost-effective manner than prior ELG rules. The EPA set the applicability dates for BATW and FGD wastewater retrofits to be "as soon as possible" beginning October 13, 2021, and no later than December 31, 2025. For facilities pursuing the FGD wastewater Voluntary Incentives Program (VIP), detailed further below, compliance shall be achieved no later than December 31, 2028. Compliance schedules for individual facilities and individual waste streams are determined through issuance of new NPDES permits by EGLE. For Monroe Power Plant, the NPDES permit contains compliance deadlines of December 31, 2023, for fly ash transport water, December 31, 2025, for BATW and December 31, 2028, for FGD. For Belle River Power Plant, the NPDES permit contains a compliance deadline of December 31, 2028, for BATW.

Q13. What are DTE Electric's options for ELG compliance?

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A13. The Company has two options to achieve compliance under the Reconsideration Rule for BATW and FGD wastewater. The first option is to design and engineer new technologies that are compliant with the ELG requirements for BATW and FGD wastewater. The second option is to pursue a compliance subcategory for BATW and FGD wastewater that EPA established within the Reconsideration Rule.

Q14. What are the compliance subcategories established within the Reconsideration Rule?

A14. One compliance subcategory allows companies to attain compliance with the ELGs for both BATW and FGD wastewater by ceasing coal burning activities, which includes retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies certify that unit(s) would retire the use of coal (or refuel), they can continue to operate those units until the unit's specified coal retirement date, which is required to be before December 31, 2028. For the electrical generating unit(s) that certify under this subcategory, companies need to maintain the existing standard limits already in effect for BATW and FGD wastewater discharges until the day of unit shut down.

In addition to the cessation of coal burning activities subcategory, the Reconsideration Rule also provides a second compliance subcategory specific to FGD wastewater. The Reconsideration Rule established Best Available Technology (BAT) standard discharge limits for FGD wastewater discharges, and further, finalized a subcategory called the Voluntary Incentive Program (VIP). Under the VIP, companies could choose to meet more stringent effluent limits established by EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chooses the VIP option, then the applicability date for FGD wastewater compliance will be December 31, 2028.

Q15. How does a company pursue compliance under a compliance subcategory from the ELG Rule?

A15. To establish compliance for either of these subcategories, companies were required to submit a Notice of Planned Participation (NOPP) to EGLE. Once submitted, companies are required to submit annual progress reports to EGLE to ensure the commitment of compliance under the subcategories.

Q16. When is a company required to submit a NOPP to enter a compliance subcategory?

A16. EPA has permitted two separate opportunities by which companies could submit NOPPs to pursue and comply with compliance subcategories. The first opportunity was from October 21, 2020, to October 21, 2021. The second opportunity was from May 30, 2023, to June 27, 2023.

Q17. Did the Company submit an NOPP filing for ELG compliance subcategories?

A17. Yes, three NOPPs have been submitted. A cessation of coal NOPP was submitted for Belle River Power Plant on October 13, 2021. A VIP NOPP was submitted for Monroe Power Plant on October 13, 2021. Lastly, a cessation of coal NOPP was submitted for Units 3 and 4 at Monroe Power Plant on April 27, 2023.

Q18. Can you describe the Cessation of Coal NOPP filing?

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A18. Yes. To establish compliance for the cessation of coal compliance subcategory detailed above, companies were required to submit an NOPP to the state permitting agency (EGLE). The cessation of coal NOPP included:

(1) identification of the electric generating unit (EGU) intended to achieve permanent cessation of coal combustion,

(2) expected date that each EGU is projected to achieve permanent cessation of coal combustion,

(3) whether each date represents a retirement or a fuel conversion,

(4) whether each retirement or fuel conversion has been approved by a regulatory body, and

(5) identification of the relevant regulatory body.

In addition, the NOPP must include a copy of the most recent Integrated Resource Plan (IRP) for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of EGU cessation under the CCR rule, or other documentation supporting that the EGU will permanently cease the combustion of coal by December 31, 2028. The NOPP must include, for each such EGU, a timeline to achieve the permanent cessation of coal combustion. Each timeline must include interim milestones and the projected dates of completion.

At the time the cessation of coal NOPP was submitted for Belle River Power Plant, preliminary modeling and strategy development related to the Company’s long term generation plan and IRP was ongoing. Due to those early efforts, the decision to submit the NOPP for Belle River Power Plant was made to preserve some options being evaluated in the strategy development. In November 2022, the Company submitted its IRP, Case No. U-21193, which included a proposed refueling of Belle River Power Plant units from coal to natural gas combustion. In July 2023, a final Order was issued that approved the refueling of Belle River Power Plant. The Company's NOPP that was submitted for Belle River Power Plant is reflective of the outcome of the IRP.

After the initial Reconsideration Rule NOPP filing date of October 13, 2021, had passed, EPA learned in meetings with trade associations and utilities that additional facilities wished to avail themselves of the compliance pathway for EGUs seeking to retire or convert to a non-coal fuel source by December 31, 2028, but were unable to make that commitment by October 13, 2021. Therefore, in March of 2023, EPA published a direct final rule to extend the deadline for plants to opt-in to the cessation of coal compliance subcategory promulgated in the Reconsideration Rule. Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193, the Company submitted a cessation of coal compliance subcategory NOPP for Monroe Power Plant Units 3 and 4 during the extension of the deadline established in EPA's direct final rule.

Q19. Can you describe the Voluntary Incentive Program (VIP) NOPP filing?

A19. Yes. To establish compliance for the VIP compliance subcategory detailed above, companies were required to submit a VIP NOPP to the state permitting agency (EGLE). The VIP NOPP for FGD wastewater included:

(1) Identification of the facility opting to comply with the VIP discharge requirements,

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(2) Specification of technology or technologies that are projected to be used to comply with those requirements, and

(3) Detailed engineering dependency chart and accompanying narrative demonstrating when and how the system(s) and any accompanying disposal requirements will be achieved by December 31, 2028.

Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193, the Company submitted a cessation of coal compliance subcategory NOPP for Monroe Power Plant Units 3 and 4 during the extension of the deadline established in EPA's direct final rule. The VIP NOPP submitted on October 13, 2021, still applies for Monroe Power Plant Units 1 and 2, as those units will continue operations until 2032.

Q20. Why did DTE Electric submit the VIP NOPP for FGD ELG compliance?

A20. For FGD compliance the Company evaluated a suite of technology options that would achieve both BAT and VIP compliance requirements for ELG FGD compliance. At the time of NOPP development, the Company was still evaluating the suite of potential compliant technologies. To ensure the Company could continue to evaluate all available technologies, including those that achieved VIP compliance, the decision was made to submit the VIP NOPP. By submitting the VIP NOPP, it allowed the Company to continue evaluating all technologies available on the market and not just technologies capable of achieving BAT.

In 2022, the Company identified an FGD compliance technology that met the VIP compliance requirements and committed the Company to the VIP NOPP.

Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193, Monroe Units 1 and 2 will continue to operate until 2032, and FGD compliance will be achieved by December 31, 2028, for those two units by achieving zero liquid discharge. As detailed above, Monroe Units 3 and 4 will achieve compliance via cessation of coal as indicated by the Company's April 27, 2023, NOPP submittal.

Q21. What is DTE Electric's compliance strategy for Belle River Power Plant?

A21. At Belle River Power Plant, fly ash is collected dry and therefore there is no Fly Ash Transport Water (FATW). Additionally, the power plant was constructed and operates without FGDs. Therefore, there is no FGD wastewater. However, the bottom ash is collected using transport water and the ELG Reconsideration Rule requires the Company to achieve compliance with BATW discharge requirements. DTE Electric submitted the NOPP on October 13, 2021, for cessation of coal at Belle River Power Plant. Please see Company Witness Guillaumin's testimony regarding the Company's commitment to convert from coal-fired to natural gas-fired operations by 2026.

Q22. What is DTE Electric's compliance strategy for Monroe Power Plant?

A22. At the Monroe Power Plant, the Company completed projects for FATW ELG compliance according to the 2015 ELG Rule and ceased water discharges related to the transport of fly ash. For BATW wastewater ELG compliance, the Company must achieve compliance by the end of 2025 and will terminate the use of water for bottom ash transport at Monroe Unit 1 and 2. For Units 3 and 4 at Monroe, the Company submitted a cessation of coal compliance subcategory NOPP on April 27, 2023. For FGD wastewater ELG compliance, the Company is pursuing

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compliance using VIP technology for Units 1 and 2 and cessation of coal NOPP for Units 3 and 4. The Company will install a VIP compliant system for Monroe Units 1 and 2 no later than the end of 2028. Monroe Units 3 and 4 will retire in 2028 according to the Company's 2022 IRP, therefore a cessation of coal NOPP was submitted providing compliance with the FGD wastewater-portion of the ELG Rule as retirement will eliminate FGD wastewater from these units. Please see Company Witness Guillaumin's testimony for further details regarding ELG compliance.

Q23. Is the EPA currently revising the 2020 ELG Reconsideration Rule?

A23. Yes. EPA has initiated a supplemental rulemaking to address discharge limits in the Steam Electric Power Generating category. EPA conducted a science-based review of the 2020 Steam Electric Reconsideration Rule under Executive Order 13990, finding that opportunities for improvement exist. Additionally, on January 3, 2023, the Unified Agenda of Regulatory and Deregulatory Actions (Regulatory Agenda) published by the United States Office of Management and Budget was updated and included a new action conducted by EPA related to ELGs. The Agenda stated the EPA, "….is taking direct final action to extend the date for existing coal-fired power plants to submit a notice of planned participation (NOPP) for the permanent cessation of coal combustion subcategory…… from October 13, 2021, to 90 days after publication of this rule in the Federal Register."[1] On March 29, 2023, EPA published the referenced direct final rule and it became effective on May 30, 2023.

[1] https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202210&RIN=2040-AG28, accessed December 21, 2023

Also, on March 29, 2023, EPA published their proposed ELG rule titled "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category". The public comment period for the proposed rule closed on May 30, 2023. According to the Regulatory Agenda, EPA plans to release their final supplemental ELG Rule by April of 2024.

Q24. Why is the Company requesting recovery of capital expenditures for projects associated with the 2020 ELG Reconsideration Rule when it is currently under revision?

A24. On August 3, 2021, the EPA issued a Federal Register notice[2] in which they announced their supplemental rulemaking to revise the 2020 ELG Reconsideration Rule as a result of their review conducted under Executive Order 13390. The Notice from EPA states, "While the Agency undertakes this new rulemaking, facilities will continue to be subject to the requirements of the 2015 Rule, as amended by the 2020 Rule, which are currently effective." The Notice goes on to also state, "EPA expects permitting authorities to continue to implement the current regulations while the Agency undertakes a new rulemaking." Based on these statements made in the August 3, 2021, Federal Register notice by EPA, the Company was required to move forward with the ELG compliance strategy and continue to implement the ELG projects referenced in Q&A9 above. In addition to the Notice, other factors specific to the project such as long lead equipment, construction seasons, and utilizing periodic outages have also driven the need to move forward with ELG compliance projects.

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[2] https://www.federalregister.gov/documents/2021/08/03/2021-16354/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source, accessed January 19, 2023

Q25. Other than above, is there other documentation stating that the Company must continue implementing ELG compliance projects based on the 2020 Reconsideration Rule even though EPA is revising it?

A25. Yes, EPA's media release[3] from July 26, 2021, in which they announce their 2021 supplemental rulemaking to revise the 2020 Reconsideration Rule states, "While the agency pursues the new rulemaking process to strengthen water pollution requirements for coal power plants, the current regulations will be implemented and enforced."

Q26. Can the Company avoid capital expenditure for bottom ash compliance on the two units proposed to retire in 2028 at Monroe?

A26. Yes. Compliance for bottom ash ELG requirements must be met no later than December 31, 2025. However, as detailed above (Q&A23), the EPA finalized the direct final rule on May 30, 2023, that reopened and extended the timeframe that NOPPs for the cessation of coal compliance subcategory could be submitted. The Company utilized the opportunity presented in the direct final rule and submitted a cessation of coal NOPP for Monroe Units 3 and 4, which are committed to retire in 2028. Consistent with the Order in the Company's 2022 IRP filing, Case No. U-21193, Monroe Power Plant Units 1 and 2 will continue to operate until 2032 and so a bottom ash compliance project will still be implemented for ELG compliance.

Q27. If the EPA's supplemental ELG Rule update becomes final as proposed, would it affect or alter planned capital projects to comply with the current ELG rule?

[3] https://www.epa.gov/newsreleases/epa-announces-intent-bolster-limits-water-pollution-power-plants, accessed March 21, 2024

A27. No. The capital projects for BATW and FGD compliance on Monroe Units 1 and 2 both rely on technologies that will ultimately result in no discharge of BATW or FGD wastewater. Zero liquid discharge technologies will always be compliant with ELG requirements as there is no discharge to regulate.

Coal Combustion Residuals

Q28. Can you describe the EPA's Coal Combustion Residuals (CCR) Rule and its impact on the Company's coal-fired units?

A28. Yes. The EPA's CCR Rule regulates how electric utilities must manage and dispose of coal combustion residuals in landfills and impoundments. On August 28, 2020, the EPA published an amendment to the CCR rule (the Part A Rule) that requires all unlined surface impoundments to cease receipt of waste and initiate closure as soon as technically feasible but by no later than April 11, 2021. The August 28, 2020, amendment also provided utilities the ability to request site-specific alternative closure deadlines through a demonstration process requiring EPA approval. On November 12, 2020, EPA published an additional amendment to the CCR rule (the Part B Rule) that allows utilities the opportunity to demonstrate that their unlined surface impoundments have an alternate liner system that is as protective as a CCR rule compliant liner system. The demonstration processes included in the Part A Rule and Part B Rule require EPA approval to continue operating CCR surface impoundments.

Q29. Can you describe the Company's strategy for each CCR unit to comply with the "Part A" amended closure provisions of the CCR Rule?

A29. Yes. The Company submitted a Part A Rule demonstration for the St. Clair Bottom Ash Basins on November 25, 2020, in accordance with 40 C.F.R. §257.103(f)(2). The demonstration requested an alternative closure deadline based on cessation of coal fired generation in spring of 2022, and a commitment to complete closure of the unit by October 17, 2023. Submission of the Part A Rule demonstration paused the April 11, 2021, deadline for the unit to cease receipt of waste. On January 11, 2022, the Company received written notice that the Part A Rule demonstration was administratively complete and confirmed that the cease receipt of waste deadline had been paused until EPA issues a final decision on the demonstration. The Company ceased operation of the coal-fired boilers at St. Clair Power Plant on May 31, 2022, completed washdowns of CCR containing equipment on August 12, 2022, and commenced physical isolation of the St. Clair Bottom Ash Basins from power plant infrastructure on September 1, 2022. These actions demonstrate that the Company has permanently ceased receipt of CCR and non-CCR waste streams at the St. Clair Bottom Ash Basins and has initiated closure by removal pursuant to 40 C.F.R. §257.102(c). The Company has therefore withdrawn the Part A demonstration, as it has already ceased receipt of waste. The Company subsequently completed dewatering and CCR removal activities in February 2023. The St. Clair Bottom Ash Basins were backfilled concurrent with and following CCR removal, and topsoil, seed and mulch placement were complete by May 2023.

On September 13, 2023, EPA acknowledged withdrawal of the Part A demonstration, stating that "EPA reviewed the Demonstration and determined that it included the required information, analyses and documentation specified under 40 C.F.R § 257.103(f)(2), and consequently determined on January 11, 2022, that

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the Demonstration was complete. The deadline to cease receipt of waste at the Bottom Ash Basins, the CCR units covered by the Demonstration, was paused between April 11, 2021, and September 1, 2022, when the unit ceased receipt of waste. See, 40 C.F.R. § 257.103(f)(3)(ii). Accordingly, EPA updated the Part A webpage [4] to reflect that the Bottom Ash Basins no longer receive waste and that DTE has withdrawn its Demonstration."

Following closure by removal activities, two rounds of samples were collected from the St. Clair Bottom Ash Basins groundwater monitoring well network. Groundwater constituent concentrations fall below groundwater protection standards as documented in the Company's Annual Groundwater Monitoring and Corrective Action Report (January 2024). Therefore, the Company completed a notification of closure in accordance with C.F.R. § 257.102(h).

Q30. Can you describe the Company's strategy for each CCR unit to comply with the "Part B" alternate liner provisions of the CCR Rule?

A30. Yes. The Company submitted Part B applications to EPA on November 30, 2020, to perform Alternate Liner Demonstrations for Belle River Bottom Ash Basins, Belle River Diversion Basin, and Monroe Fly Ash Basin. The Company received notice of EPA's proposed denial on January 25, 2023. The Company is continuing with projects at each facility to comply with the CCR rules and support operating the plants. The proposed denials affect each facility as follows:

[4] Coal Combustion Residuals (CCR) Part A Implementation | US EPA available at https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation

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Belle River Bottom Ash Basins and Diversion Basin:

As discussed in Witness Guillaumin's testimony, the Company has executed a project to retrofit the Bottom Ash Basins with a CCR-compliant liner system and close the Diversion Basin by removal. The project was completed in 2023 in accordance with regulatory timelines. On September 21, 2023, the Company withdrew the Part B application, as it had already ceased receipt of waste in any unlined portion of the units.

On October 30, 2023, EPA acknowledged withdrawal of the Part B application, stating that "EPA reviewed the application and determined that it included the required information, analyses and documentation specified under 40 C.F.R. § 257.71(d)(1), and consequently determined on January 11, 2022, that the application for the Bottom Ash Basins and the Diversion Basin was complete. On January 25, 2023, EPA issued a proposed decision to deny the application for both the Bottom Ash Basins and the Diversion Basin. In accordance with 40 C.F.R. § 257.71(d)(1)(iii)(A), the deadline to cease receipt of waste for the Bottom Ash Basins and the Diversion Basin was tolled the entire period between April 11, 2021, and July 6, 2023, and May 16, 2023, respectively, when the units ceased receipt of waste."

Following closure by removal activities for the Diversion Basin, two rounds of samples will be collected from the groundwater monitoring well network to certify that closure by removal is complete. Final notification of closure completion is expected in 2024.

Monroe Fly Ash Basin:

The Company was already in process of developing alternative capacity at Monroe by converting the existing wet fly ash handling system to a dry system in accordance with the 2015 ELG rule. The dry fly ash conversion is complete, and the Fly Ash Basin received its last known shipment of waste on December 29, 2023, and as discussed in the Notification of Intent to Close, the Company has initiated closure within the appropriate regulatory timeframes. Therefore, on January 25, 2024, the Company withdrew the Monroe Fly Ash Basin Part B Application.

Q31. Can you describe the Company's strategy for closure of Monroe Bottom Ash Basin?

A31. Yes. The Company ceased receipt of CCR at the Monroe Bottom Ash Basin prior to the effective date of the 2015 CCR rule. Consequently, the Company prepared and placed in the facility's operating record a notice of intent to initiate closure on December 11, 2015, in accordance with §257.100. The Monroe Bottom Ash Basin was therefore considered an inactive CCR surface impoundment. Section 257.100 was later remanded and revised by EPA, subjecting inactive CCR surface impoundments to all the requirements applicable to existing CCR surface impoundments but on an alternative timeframe. In April 2020, it was determined that the Monroe Bottom Ash Basin did not meet the requirements of §257.60 (placement above the uppermost aquifer) and was subject to closure under the requirements of §257.101(b)(1)(i) and therefore must cease receipt of both CCR and non-CCR waste streams as soon as technically feasible, but no later than April 11, 2021, and close in accordance with §257.102. The Company ceased receipt of non-CCR waste streams and initiated closure on October 21, 2020 and is currently progressing through final steps of closure by removal of all CCR.

Q32. Please explain why the site improvements at Sibley Quarry Landfill are necessary and needed to support CCR compliance.

A32. Improvements to infrastructure at Sibley Quarry Landfill have been made to enhance the storage capability to accept the CCR material from the Monroe Bottom Ash Basin and Monroe Power Plant production CCR. These improvement projects were necessary because the Monroe Fly Ash Basin and Vertical Extension Landfill could not accept CCR beyond 2023. Sibley Quarry Landfill has ample permitted capacity and was therefore selected as the disposal location for the CCR material removed from the Monroe Bottom Ash Basin, and Monroe production CCR. The Company has transported nearly 1,000,000 tons of CCR from the Monroe Bottom Ash Basin through 2023 and will receive additional CCR material in 2024. Certification of the CCR removal from the Monroe Bottom Ash Basin is expected by late 2024. Company Witness Guillaumin details the costs associated with these improvement projects.

Q33. Please explain why the Monroe Fly Ash Basin Closure project is necessary and what are the required closure time frames.

A33. The Monroe Fly Ash Basin is an existing unlined CCR surface impoundment as determined under 40 C.F.R. §257.71(a). Therefore, it is subject to the requirements of 40 C.F.R. §257.101(a)(1), which states that the unit must cease receipt of waste and initiate closure as soon as technically feasible, but by no later than April 11, 2021. As discussed in Question 26 above, the Company submitted a Part B

Alternate Liner Demonstration Application for the Monroe Fly Ash Basin on November 30, 2020, in accordance with 40 C.F.R. §257.71(d)(1). On January 11, 2022, EPA notified the Company that the application was administratively complete, and that EPA will pause the facility's deadline to cease receipt of waste until issuance of a final decision under 40 C.F.R. §257.71(d)(2)(iii)(C). The Company has not received a final decision under 40 C.F.R. §257.71(d)(2)(iii)(C) as of this filing. However, the Monroe Fly Ash Basin received the known final receipt of waste on December 29, 2023, and initiated closure within 30 days to comply with 40 C.F.R. §257.102(e)(1). As documented in the Notification of Intent to Close, the Company has ceased receipt of waste and initiated closure.

To comply with the closure timeframes of 40 C.F.R. §257.102(f)(1), the Company must complete closure within five years of commencing closure activities. Therefore, the Company is targeting 2029 to complete the closure of this 410-acre basin. If needed, 40 C.F.R. §257.102(f)(2) provides an opportunity for up to five 2-year extensions, provided the owner or operator can demonstrate the factual circumstances which prevented completion of closure within the baseline five years.

Q34. Can you describe how EPA's proposed Legacy CCR Rule could affect or alter planned capital projects to comply with the current CCR rule?

A34. Yes. The proposed Legacy CCR Rule does not affect the planned capital projects being implemented to comply with the current CCR Rule. On May 18, 2023, EPA published a proposed rule titled Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR

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Surface Impoundments. The draft rule proposes to establish regulatory requirements for inactive surface impoundments at inactive facilities, and also apply groundwater monitoring, corrective action, closure, and post closure care requirements for all CCR Management Units (CCRMU) at regulated CCR facilities. Importantly, the proposed rule applies to currently unregulated CCR, and the CCR-related capital projects described in Witness Guillaumin's testimony are tied to regulated CCR units that will proceed as planned.

Q35. Does this complete your direct testimony?

A35. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. LEPCZYK

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC as Assistant Treasurer and Director of Corporate Finance, Insurance and Development.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from Georgetown University in 2004 with a Bachelor of Business Administration degree, with a concentration in International Business. In 2008, I graduated with my MBA from the University of Michigan, with a focus in Finance and Corporate Strategy.

Q4. What is your work experience?

A4. I began my employment with Ford Motor Company in the summer of 2004 as a financial analyst within that company's Dearborn Stamping facility. In 2006, I left to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company, a management consultancy, where I focused on the automotive and industrial sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE Energy.

In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where I was the lead analyst for various projects and studies primarily relating to the Gas

Storage and Pipeline business. In 2014, I formally accepted a position within the Gas Storage and Pipeline team as Manager in their strategy group where I was responsible for various economic analyses (e.g., natural gas supply and demand fundamentals) and for assessing potential new acquisition opportunities. In 2016, I accepted the position of Manager for the Corporate Development team where I was responsible for managing DTE Energy's capital investment process and various valuation processes (for example, DTE Energy's annual Goodwill impairment assessment). In addition, I led broader strategy initiatives including the analysis, which ultimately led to our decision to spin off the Midstream business segment.

In 2021, I accepted my current position, Assistant Treasurer and Director of Corporate Finance, Insurance and Development.

Q5. What are your current duties and responsibilities?

A5. I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company's capital investment approval and review process along with managing the Company's property and liability insurance function.

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Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes, I have. I have sponsored testimony in the following cases:

U-20836	DTE Electric 2022 General Rate Case
U-21193	DTE Electric 2022 Integrated Resource Plan
U-21338	DTE Electric 2023 Securitization
U-21291	DTE Gas 2024 General Rate Case
U-21297	DTE Electric 2023 General Rate Case

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Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to support DTE Electric's projected capital structure and the cost of its long- and short-term debt to be used in the determination of DTE Electric's overall rate of return in this proceeding.

Q8. How is your testimony organized?

A8. My testimony is organized as follows:

I. Summary of Recommendations
II. Development of Capital Structure
III. Development of Cost Rates
IV. Securitization
V. Summary and Conclusions

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-1	A2	Historical Financial Metrics
A-4	D2	Historical Cost of Long-Term Debt
A-4	D3	Historical Cost of Short-Term Debt
A-4	D4	Historical Cost of Preferred and Preference Stock
A-4	D5	Historical Cost of Common Shareholders' Equity
A-11	A2	Projected Financial Metrics
A-14	D1.1	Peer Group Common Equity
A-14	D2	Projected Cost of Long-Term Debt

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A-14	D3	Projected Cost of Short-Term Debt
A-14	D4	Projected Cost of Preferred and Preference Stock
A-18	H1	Current and Historical Credit Ratings
A-18	H2	Recent Utility Corporate Bond Issuances

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

I. SUMMARY OF RECOMMENDATIONS

Q11. What permanent capital structure are you recommending for the projected test year to be utilized in determining the overall rate of return calculation for DTE Electric?

A11. I am recommending a projected permanent capital structure of 50% long-term debt and 50% common equity. Permanent capital is long-term perpetual capital. Common equity, preferred stock and long-term debt are sources of permanent capital. Since the Company does not have any preferred stock, I am recommending the permanent capital structure to be made up of 50% long-term debt and 50% common equity. This permanent capital structure is reflected in DTE Electric's projected permanent capital structure as of December 31, 2025, as shown in Exhibit A-14, Schedule D1, which is supported by Company Witness Vangilder. This capital structure is necessitated by the business and financial risks confronting DTE Electric, which I will discuss in greater detail later in my testimony.

Q12. What is your forecast for DTE Electric's cost of long-term debt, short-term debt, and preferred stock for the 12-month period ending December 31, 2025?

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A12. I am forecasting 4.24% for the cost of DTE Electric's long-term debt, and 5.76% for the cost of DTE Electric's short-term debt. The Company does not have preferred stock, and therefore it has no cost rate. Exhibit A-14, Schedule D2 supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports the cost rate for short-term debt.

II. DEVELOPMENT OF CAPITAL STRUCTURE

Q13. What do you mean by capital structure?

A13. A company's capital structure includes the amount of equity and debt necessary to support the operations of its business and is defined differently by regulators, finance professionals, and rating agencies. Total regulatory capital structure typically includes long-term debt, short-term debt, preferred stock, common equity, deferred taxes, deferred job development investment tax credits, and deferred investment tax credits. Permanent capital structure includes only long-term debt and equity. Rating agencies calculate a company's capital structure using short-term debt, long-term debt, preferred stock, common equity, and other adjustments. The rating agencies adjust debt to include items like capital and operating leases, unfunded pension liabilities, power purchase agreements, and asset retirement obligations.

Q14. Why is a sound capital structure important?

A14. It is important to have a financially sound capital structure in order to ensure that a company can obtain needed capital. A sound capital structure produces capital costs that are reasonable and equitable. Also, it is important that the overall return on capital be sufficient to assure financial confidence in a firm and to allow it to raise the funds that are necessary to operate its business at reasonable costs and terms. A sound capital structure is in the best interests of the customers as it ensures the continued viability of the company.

Q15. How does risk affect a firm's capital structure?

A15. In general, a firm such as DTE Electric faces two types of risk: business risk and financial risk. Business risk is a result of systemic and non-systemic risk. Systemic risks are broad economic risks faced by all firms. Non-systemic risks are risks specifically identified as those faced by the individual firm. Financial risk is the risk that common equity shareholders face to the extent that a firm issues debt to finance real assets. Debtholders (also known as bondholders) have priority over equity shareholders in the event of corporate bankruptcy. Thus, the greater the amount of debt held by a firm, the greater the risk to equity shareholders. It is essential that a firm recognizes the dynamics of these risks and adjusts its underlying debt and equity components to produce a sound capital structure.

Q16. How does a company's capital structure impact its ability to attract capital?

A16. Having a weak or highly leveraged capital structure may lead to higher required returns on equity and a higher cost of debt. It also can impact the company's ability to obtain capital. For example, a company with a highly leveraged capital structure may lose its investment grade rating from the rating agencies. Non-investment grade companies have a limited investor base and a more limited access to capital than investment grade companies. Moreover, during periods of diminished capital liquidity, even investment grade companies can have limited access to new capital sources. It is important to consider how extreme market reactions to singular events impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. Furthermore, rating agencies allow little or no time for a company to correct and improve its capital structure before lowering its credit rating. Conversely, companies must be proactive to target and achieve the midpoint of the range of rating agency financial metrics to have a better chance to maintain current ratings.

Q17. Will higher debt levels in a capital structure affect the cost of debt?

A17. Yes. The cost of debt increases as more debt is added to the capital structure. Further, higher debt levels can increase the risk of a downgrade by the rating agencies. A lower credit rating means greater credit risk such that investors will require a higher return to invest in a company, thereby increasing the cost of debt for that company.

Q18. For DTE Electric's defined projected test year, what capital structure are you recommending for DTE Electric in the instant case?

A18. For the projected test year, the permanent capital structure that I am recommending includes long-term debt and equity as shown on Exhibit A-14, Schedule D1, that is supported by Witness Vangilder. Within this regulatory capital structure, I am recommending a projected test year permanent capital structure that has 50% long-term debt and 50% common equity. This is the same permanent capital structure authorized by the Commission in the last general rate case, Case No. U-21297.

Q19. Does the Company believe that a 50/50 capital structure is the optimal capital structure for DTE Electric?

A19. No. To reduce the number of contested positions in the instant case, the Company is using the structure authorized in the December 1, 2023 order in Case No. U-21297. However, as the Company has argued in past rate cases, it believes the more appropriate capital structure for DTE Electric is closer to that of its peers. Exhibit A-14, Schedule D1.1 shows DTE Electric peers having a capital structure made up of 48% long-term debt and 52% common equity. A 50% equity level gives the Company less protection in the event of an unforeseen market event and may impact DTE Electric's ability to access capital during the future test period should an unforeseen market shock occur.

Q20. Is the proposed ratio of 50% common equity to total permanent capitalization in line with DTE Electric's peers?

A20. No. The common equity ratio requested in the instant case is lower than that of the Company's peers. As shown on Exhibit A-14 Schedule D1.1, the average equity ratio for DTE Electric peers was approximately 52%. DTE Electric's targeted 50% equity ratio is a reasonable level given that the average ratio of the peer group is higher at 52%. The data was obtained from S&P Global Market Intelligence (SNL) for the most recent fiscal year available per peer company. DTE Electric believes its requested 50% is reasonable and below the equity ratio of its peers across the country and within Michigan.

Q21. Does the intense capital investment program contribute to the need for a higher level of equity in general within the capital structure?

A21. Yes, it is imperative that DTE Electric be viewed as a financially sound firm with a solid investment grade rating to ensure the reasonableness and competitiveness of capital costs. DTE Electric will be financing and funding over $7.9 billion of electric capital expenditures for the period January 2023 through December 2025 (see Exhibit A-12 Schedule B5). In a period of intense capital investment, a sound capital structure and a favorable regulatory environment are essential to maintain the financial well-being of the Company. Should the Company face any unforeseen or negative impacts to its financial health, a higher equity balance may be needed. The common equity balance and equity ratio projected for the test year in the instant case will hopefully enable the Company to maintain strong credit ratings and withstand any shocks in the financial markets, thereby ensuring a smooth implementation of its capital expenditure program.

Q22. Is DTE Electric committed to maintaining a 50% equity ratio in its capital structure?

A22. Yes. At December 31, 2022, DTE Electric's equity ratio was 50%. DTE Electric is committed to maintaining a 50% equity ratio and has demonstrated its commitment to its targeted equity ratio by receiving equity infusions from DTE Energy. DTE Energy has made reasonable efforts to strengthen DTE Electric's credit quality by infusing over $2.3 billion of common equity from 2018-2022. DTE Electric has received equity infusions totaling $760 million in 2023 and will infuse the amounts necessary in future years to maintain a 50% common equity ratio.

III. DEVELOPMENT OF COST RATES

Q23. What were DTE Electric's historical financial and ratemaking metrics from 2018 through 2022?

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A23. DTE Electric's historical financial and ratemaking metrics for each of the previous five years (2018 through 2022) are detailed in Exhibit A-1, Schedule A2. The historical financial calculations include year-end financial metrics and are calculated on a financial basis from DTE Electric's financial reports. The historical ratemaking metrics include year-end financial metrics and are calculated from DTE Electric's annual regulatory filings.

Q24. What is the cost of long-term debt outstanding at December 31, 2022?

A24. Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding at December 31, 2022. As shown in the exhibit and schedule, the cost of long-term debt also includes agent's fees, commissions, and financing expenses and is calculated on the net proceeds to the Company. The weighted average cost of debt is computed based on the total annual costs to the Company divided by the total principal amount outstanding at year-end. The cost of long-term debt at December 31, 2022 was 3.77%.

Q25. What is the cost of short-term debt outstanding at December 31, 2022?

A25. The cost of short-term borrowings for the 13-month period ended December 31, 2022 was 2.75%. The cost of short-term debt consists of the 1) interest rate on short-term borrowings, and 2) credit facility fees associated with the credit agreements necessary for the issuance of short-term debt. See Exhibit A-4, Schedule D3.

Q26. What was the approved cost of equity as of December 31, 2022?

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A26. DTE Electric's authorized cost of common shareholders' equity as of December 31, 2022 was 9.9% and was approved in Case No. U-20836. DTE Electric does not have any preferred stock. See Exhibit A-4, Schedules D4 and D5.

Q27. What does DTE Electric project its financial metrics to be in the projected test year?

A27. DTE Electric's forecasted ratemaking metrics are available in Exhibit A-11, Schedule A2. Forecasted calculations include metrics for the fully projected test year. The forecasted ratemaking metrics for the projected test year are to be reported assuming (i) full rate relief as requested, and (ii) zero rate relief.

Q28. What is the purpose of Exhibit A-14, Schedule D2?

A28. The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected weighted average long-term debt costs as of December 31, 2025. Starting with the actual December 31, 2022 long-term debt outstanding, any known and measurable changes for each year were made to arrive at the projected balance as of December 31, 2025. Known and measurable changes that have occurred or are projected to occur from January 1, 2023 through December 31, 2025 include:

Table 1 Issuances and Redemptions

Long-Term Debt Activity	Amount ($000)	Date	Interest Rate
Issuance	600,000	Mar-23	5.20%
Issuance	600,000	Mar-23	5.40%
Issuance	100,000	Jun-23	3.88%
Redemption	(102,000)	Sep-23	4.31%
Redemption	(100,000)	Oct-23	5.19%
Redemption	(300,000)	Dec-23	3.65%
Issuance	575,000	Mar-24	5.65%
Redemption	(100,000)	Mar-24	3.65%
Issuance	800,000	Mar-25	5.62%
Redemption	(350,000)	Mar-25	3.38%
Issuance	500,000	Jul-25	5.62%
Net change in debt	2,223,000		

The 2024 and 2025 debt issuances are assumed to be 30-year fixed rate bonds with an interest rate of 5.65% and 5.62%, respectively. The interest rate for the debt issuances is based on forward 30-year Treasury rates and adding a spread of 148 basis points which is the spread on the Company's last 30-year debt issuance. Including the planned long-term debt issuance, the weighted average long-term debt cost as of December 31, 2025 is projected to be 4.24%.

Q29. Why did you use long-term debt cost on a net proceeds basis?

A29. The actual costs would be understated if the net proceeds were not used in the base calculation. The net proceeds methodology accounts for underwriters' compensation and other financing expenses and is shown on Exhibit A-14, Schedule D2. A portion of any amount financed is used to fund these costs, such that the Company has access to less than the full amount financed. As a result,

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these fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the effective cost of the issuance above the stated coupon rate.

Q30. How did you determine the interest rate on short-term debt on Exhibit A-14, Schedule D3?

A30. The total cost of short-term debt is comprised of the interest rate on the short-term debt plus associated facility fees. Supporting credit facilities are required by the rating agencies and investors for DTE Electric to issue commercial paper. These facilities have costs associated with them. The interest rate on the short-term debt was determined by adding 20 basis points (bps) to the 1-month short-term index. Due to the uncertainty of interest rates and Fed Fund rate changes, the Company is using the short-term debt index and short-term debt rate in effect as of December 2023. Interest rates have been very volatile recently with market uncertainty around when and if the Fed will lower the Fed Funds rate. Given this unpredictability, the Company feels it is prudent to use the current and known rate. A spread of 20 bps was added to the index because that is the current spread on DTE Electric's commercial paper issuances. See Exhibit A-14, Schedule D3.

The current 1-month short-term index is 5.31%. Adding the spread of 20 bps to the index brings the interest rate on short-term borrowings to a total of 5.51%. The cost of the facility fees for the 12-month period ending December 31, 2025, is $1.3 million. This cost was divided by the average outstanding short-term debt balance of $509 million and equates to 0.25% of the cost of short-term debt. Adding the interest rate on short-term debt of 5.51% to the facility fee cost of 0.25%, results in the total cost of short-term debt of 5.76%.

Q31. What is the purpose of Exhibit A-14, Schedule D4?

A31. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferred or preference stock during the projected test period.

Q32. What are the Company's current and historical credit ratings?

A32. Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and historical credit ratings, along with associated rating agency outlooks, for the previous five years as published by Standard & Poor's (S&P), Moody's Investors Service (Moody's), and Fitch Ratings. The credit ratings include senior unsecured debt, senior secured debt, and commercial paper ratings.

Q33. Have there been recent public utility bond issuances?

A33. Yes. I have provided details of public utility bond issuances for the three-month period prior to, through the three-month period after, each of DTE Electric's long-term debt offerings issued during the 24 months prior to December of 2023. This summary includes the offer date, issuing company, type of offering (either secured or unsecured), Moody's and S&P credit ratings, maturity, tenor, amount of offering, coupon, and issue spread. See Exhibit A-18, Schedule H2.

IV. SECURITIZATION

Q34. Does the Company intend to securitize additional regulatory assets?

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A34. Yes. On June 22, 2023, in Case No. U-21338, the Commission approved DTE Electric's application to issue securitization bonds for up to $601.6 million in costs associated with the closure of the Trenton Channel and St. Clair coal-fired generation plants. The securitization financing was completed in November of 2023. The Company is planning a future securitization of the tree trim regulatory assets once the balance is large enough to make a financing feasible.

Q35. How has the tree trim surge regulatory asset been financed in prior rate cases?

A35. On May 2, 2019, the Commission issued its order in Case No. U-20162 whereby the Company was authorized a return on the tree trim surge regulatory asset at the short-term debt cost rate of 3.56%. (p. 80). In Case No. U-20561, Case No. U-20836, and Case No. U-21297 the return on tree trim surge regulatory asset was calculated at the authorized short-term debt rate.

Q36. What does the Company believe is the appropriate financing rate for tree-trim assets?

A36. Given the temporary status, defined in Case No. U-20162, of the tree trim surge regulatory asset, the Company did not pursue financing with permanent long-term debt and equity capital, but rather financed with short-term working capital including short-term debt. Thus, this was matching the financing costs with the return the Company was earning on the regulatory asset. In securitization Case No. U-21015 and Case No. U-21338, the Commission considered the regulatory asset to have been financed with permanent capital and specified that proceeds of the securitization should be used for the repayment of long-term debt and equity. Consistent with that financing order, the Company's position is that any future tree

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trim surge regulatory asset amounts should be treated as being financed with permanent long-term debt and equity capital and receive the respective return.

Q37. How does the Company propose to treat the tree trim surge regulatory asset in this instant case?

A37. In Case No. U-21297, the Company reiterated its position that any future tree trimming surge expenditures be financed through the issuance of long-term debt and equity until the time the Company can execute a securitization financing for these amounts., I have directed Witness Vangilder to calculate the return on projected tree trim surge regulatory assets using the cost of permanent long-term debt and equity capital.

<u>V. SUMMARY AND CONCLUSIONS</u>

Q38. Can you summarize your recommendation and conclusions?

A38. Due to the financial and business risks faced by the Company, a projected permanent capital structure of 50% long-term debt and 50% common equity is reasonable and prudent. DTE Energy has taken reasonable actions to strengthen DTE Electric's credit quality and has done so by infusing over $2.3 billion of common equity from 2018 through 2022 and will continue to do so as needed. The plan calls for additional equity infusions and retained earnings growth through the projected test period in the amount necessary to maintain the Company at no less than a ratio of 50% equity to permanent capital at December 31, 2025. For the projected year, the cost of short-term debt is projected to be 5.76%, and the cost of long-term debt is projected to be 4.24%. I believe these expenses and measures are reasonable, prudent and necessary.

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Q39. Does this complete your direct testimony?

A39. Yes, it does.